Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

Darcy L. Endo-Omoto
Vice President
Government & Community Affairs

July 20, 2009

The Honorable Chairman and Members of the
Hawaii Public Utilities Commission
Kekuanaoa Building, 1st Floor
465 South King Street
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Docket No. 2008-0083 – Hawaiian Electric 2009 Test Year Rate Case
Hawaiian Electric Supplemental Testimonies, Exhibits and Workpapers

In accordance with the *Interim Decision and Order* issued July 2, 2009 in Docket No. 2008-0083, enclosed for filing are Hawaiian Electric Company, Inc.'s ("Hawaiian Electric" or "Company") Supplemental Testimonies, Exhibits and Workpapers for the following Hawaiian Electric witnesses:

- HECO ST-1 – Robert A. Alm
- HECO ST-3 – Peter C. Young
- HECO ST-4 – Ross H. Sakuda
- HECO ST-7 – Dan V. Giovanni
- HECO ST-8 – Robert K.S. Young
- HECO ST-9 – Darren S. Yamamoto
- HECO ST-10 – Alan K.C. Hee
- HECO ST-10B – Jeff Makholm, Ph.D.
- HECO ST-11 – Patsy H. Nanbu
- HECO ST-12 – Russell R. Harris
- HECO ST-13 – Julie K. Price
- HECO ST-13A – Leonard E. Smothermon
- HECO ST-14 – Bruce K. Tamashiro
- HECO ST-15 – Faye R. Chiogioji
- HECO ST-15A – Gayle Furuta-Okayama
- HECO ST-15B – Mike H. McInerny
- HECO ST-15C – Leon R. Roose
- HECO ST-15D – Scott W.H. Seu
- HECO ST-16 – Lon K. Okada
- HECO ST-17 – Lorie Ann Nagata

- HECO ST-17A – Robert C. Isler
- HECO ST-17B – Anthony L Lunardini
- HECO ST-17C – Brenner Munger
- HECO ST-17D – Ken T. Morikami
- HECO ST-17E – Tom C. Simmons
- HECO ST-20 – Tayne S.Y. Sekimura
- HECO ST-21 – Steven M. Fetter
- HECO ST-22 – Peter C. Young

Information contained in the HECO ST-9 testimony and exhibit HECO-S-901 is confidential and is not to be provided or disclosed to the general public. The April and May 2009 information is submitted under protective order as the April and May 2009 information is confidential until publicly disclosed in the financial statements submitted to the Securities and Exchange Commission ("SEC"), which is scheduled for August 2009. The information will not be considered final until the Company issues its financial statements to the SEC. Should any of the preliminary information change, the Company will provide the revisions as soon as practicable.

Information contained in the HECO ST-15A testimony and exhibits HECO-S-15A02 and HECO-S-15A03 is confidential and is not to be provided or disclosed to the general public. The information was gathered as part of private compensation and salary surveys. Survey participants are not linked specifically to the data in question, and the survey data and results are provided only to the participants. The information is deemed confidential and solely for the use as intended. Absent authorization from the surveyor the information is provided subject to the terms of the Protective Order filed November 21, 2008 in this proceeding.

Information contained in the HECO ST-15B testimony and exhibit HECO HECO-S-15B04 is based on third-party proprietary data, which is confidential and is submitted pursuant to the Protective Order filed November 21, 2008 in this proceeding.

Sincerely,

Darcy L. Endo-Omoto
Vice President
Government & Community Affairs

Enclosures

cc: Division of Consumer Advocacy
Department of Defense

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF HAWAII

In the Matter of the Application of	)	
	)	
HAWAIIAN ELECTRIC COMPANY, INC.	)	Docket No. 2008-0083
	)	
For Approval of Rate Increases and Revised Rate Schedule and Rules	)	

FILED

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Public Utilities Commission

HECO
2009 TEST YEAR

HECO SUPPLEMENTAL TESTIMONIES AND EXHIBITS

Book 1 of 3

July 20, 2009

Hawaiian Electric Company, Inc.

Docket No. 2008-0083

Application for Approval of Rate Increases and
Revised Rate Schedules and Rules

SUPPLEMENTAL TESTIMONIES AND EXHIBITS SPONSORSHIP LIST

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HECO ST-9	D. S. Yamamoto
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HECO-S-901	Uncollectibles through June 2009 (preliminary)

HECO ST-10	A. K. C. Hee
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HECO ST-10B	J. D. Makholm
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HECO-S-10B00	Educational Background and Experience

HECO ST-11	P. H. Nanbu
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HECO-S-1101	Administrative and General Expenses, 2007-2009
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HECO-S-1106	Regulatory Asset - NPPC vs NPPC in Rates Pension Asset, 1987-2009
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HECO ST-12	R. R. Harris
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HECO ST-13	J. K. Price
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HECO ST-15C	L. R. Roose
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HECO ST-17	L. A. Nagata
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HECO-S-1701	Campbell Industrial Park Generating Station and Transmission Additions, Plant Additions
HECO-S-1702	Updated Exhibit HECO-1703
HECO ST-17A	R. C. Isler
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HECO-S-17A00	Educational Background and Experience
HECO-S-17A01	Total Estimated Cost for the CIP Generation Addition and Transmission Additions Projects (Y-49000)
HECO-S-17A02	Summary Table of Cost Variances for CIP CT-1 Generation Project

HECO ST-21	S. M. Fetter
TESTIMONY	Financial Integrity
HECO ST-22	P. C. Young
TESTIMONY	Cost-of-Service Study and Rate Design
HECO-S-2201	Summary of Class Revenue Requirements and Class Rates of Return at Current Effective Rates and at Proposed Rates Cost of Service Based on Minimum System Study
HECO-S-2202	Summary of Class Revenue Requirements and Class Rates of Return at Current Effective Rates and at Proposed Rates Cost of Service Based on All Distribution Network Demand Related

HECO ST-1
DOCKET NO. 2008-0083

SUPPLEMENTAL TESTIMONY OF
ROBERT A. ALM

EXECUTIVE VICE PRESIDENT

HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Policy Statement

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INTRODUCTION

Q. Please state your name and business address.

A. My name is Robert A. Alm and my business address is 900 Richards Street, Honolulu, Hawaii.

Q. By whom are you employed and in what capacity?

A. I am the Executive Vice President for Hawaiian Electric Company, Inc. ("Hawaiian Electric" or "Company").

Q. What is the purpose of your supplemental testimony?

A. The purpose of my supplemental testimony is to state the Company's policy position on the *Interim Decision and Order* ("ID&O") issued on July 2, 2009 in this proceeding, and to address some of the more critical issues that arise from the ID&O. The Commission has identified a number of concerns, including the cost and usefulness of the Campbell Industrial Park ("CIP") Combustion Turbine Unit 1 ("CT-1"), costs associated with the Hawaii Clean Energy Initiative ("HCEI") and the Energy Agreement, Hawaiian Electric employee wage and salary levels and benefits and staffing levels. We appreciate the opportunity to address those concerns in this testimony and the supplemental testimonies submitted by the Company's other witnesses. Hawaiian Electric's position is that these costs are reasonable and should be recovered through interim and final rates in this proceeding.

Q. Is the Company submitting other supplemental testimonies to address the issues raised in the ID&O?

A. Yes. The table below identifies the witnesses who are filing supplemental testimony.

Supplemental #	Subject	Witness
HECO ST-1	Policy Statement	Robert A. Alm
HECO ST-3	Total Operating Revenues	Peter C. Young
HECO ST-4	Continued Need for Campbell Industrial Park CT-1	Ross H. Sakuda
HECO ST-7	Production Operations and Maintenance Expenses	Dan V. Giovanni
HECO ST-8	Transmission and Distribution Operations and Maintenance	Robert K. S. Young
HECO ST-9	Customer Accounts, Uncollectibles	Darren S. Yamamoto
HECO ST-10	Customer Solutions Head Count, Base Demand-Side Management Expenses	Alan K. C. Hee
HECO ST-11	Administrative and General Expenses	Patsy H. Nanbu
HECO ST-12	Insurance	Russell R. Harris
HECO ST-13	Employee Benefits	Julie K. Price
HECO ST-14	Miscellaneous A&G Expenses	Bruce K> Tamashiro
HECO ST-15	Employee Headcount	Faye Chiogioji
HECO ST-16	Accumulated Deferred Income Taxes	Lon K. Okada
HECO ST-17	CIP CT-1 Plant Additions	Lorie Ann Nagata

HECO ST-20	Purchased Power Adjustment Clause	Tayne S. Y. Sekimura
HECO ST-21	Financial Integrity	Steven M. Fetter
HECO ST-22	Cost-of-Service Study and Rate Design	Peter C. Young

Q. Is the Company introducing any new witnesses for the submission of supplemental testimony?

A. Yes. The following new witnesses are submitting supplemental testimony:

Supplemental #	Subject	Witness
HECO ST-10B		Dr. Jeff D. Makholm
HECO ST-13A	Pension Plan and OPEB Plan Funding	Leonard E. Smothermon
HECO ST-15A	Merit Employee Wage Increase	Gayle Furuta-Okayama
HECO ST-15B	Non-Merit Employee Wage Increases; Employee Electricity Rate Discount	Michael H. McInerny
HECO ST-15C	Employee Count	Leon Roose
HECO ST-15D	Employee Count	Scott Seu
HECO ST-17A	Campbell Industrial Park Generating Station and Transmission Additions Project – Costs	Robert C. Isler
HECO ST-17B	Campbell Industrial Park CT-1 Cost Basis and Factors	Anthony L. Lunardini
HECO ST-17C	Cost Variance Explanations for Power Supply Capital Expenditure Applications	Brenner Munger

HECO ST-17D	Cost Estimating for Energy Delivery Projects	Ken T. Morikami
HECO ST-17E	Cost Recovery of Generating Unit CIP CT-1	Thomas C. Simmons

A number of the supplemental testimonies compile the citations for information on the record that would facilitate the Commission's review of the issues it has raised in the ID&O.

INTERIM DECISION AND ORDER

Q. Please summarize the ID&O.

A. On July 2, 2009, the Commission issued the ID&O for this proceeding, approving the interim rate relief for Hawaiian Electric, as set forth in its Statement of Probable Entitlement, filed on May 18, 2009, with the exception of certain items identified in Sections II.1 and II.2 of the ID&O. It directed Hawaiian Electric to exclude the costs described in Sections II.1 and II.2 from interim rate relief and to file revised schedules together with written explanations as to the amounts removed, and any other downward adjustments made to the schedules due to the exclusion of the costs and mechanisms from interim relief, and directed the Consumer Advocate and the DOD to file any comments on Hawaiian Electric's revised schedules within five days of the date of Hawaiian Electric's filing. Section III of the ID&O specified additional items that may be at issue in the evidentiary hearing. The ID&O allowed the "Parties" in this proceeding – i.e., Hawaiian Electric, the Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs ("Consumer

Advocate") and the Department of Defense ("DOD") – to file additional testimonies by July 20, 2009 to address the provisions of the ID&O (at 21).

Q. Did Hawaiian Electric file revised schedules with written explanations of the amounts removed from interim rate relief?

A. Yes. On July 8, 2009, the Company filed revised schedules and explanations of certain adjustments to its test year estimates as Sections II.1 and II.2 of the ID&O required.

Q. What interim increase amount did the revised schedules reflect?

A. Exhibit 1 of the Company's July 8, 2009 filing reflected an interim increase amount of $61,098,000 over revenues at current effective rates. This was a reduction of $18,713,000 compared to the interim increase amount of $79,811,000 that the Company proposed in its Statement of Probable Entitlement and to which the Consumer Advocate and the DOD agreed in settlement discussions.[1]

Q. Did the Consumer Advocate or the DOD file any comments on Hawaiian Electric's revised schedules?

A. Yes. On July 15, 2009, the Consumer Advocate filed its comments, which stated that "based on the analysis conducted in the time available, the Consumer Advocate believes that Hawaiian Electric's proposed adjustments were conservatively prepared, views the revised schedules as being in general compliance with the Commission's Interim D&O and does not have any objections to HECO's filing." Hawaiian Electric is not aware that the DOD filed any comments.

INTERIM RATE RELIEF

Q. Given what has transpired as a result of the ID&O, what does Hawaiian Electric request?

A. Hawaiian Electric respectfully requests the Commission to immediately approve the interim rate increase of $61,098,000 over revenues at current effective rates, as reflected in the revised schedules that Hawaiian Electric filed on July 8, 2009, to be effective upon issuance of the order. Although it is less than the interim increase amount that the Company requested in the Statement of Probable Entitlement, it would provide much needed rate relief on an immediate basis.

Q. Why is it important for the Company to immediately receive this interim rate relief?

A. Under the average test year concept followed in reaching the settlement, the agreed upon increase in revenues is the amount needed at the beginning of the test year to provide a reasonable opportunity to earn the fair rate of return of the test year. The later in the test year that the increase is received, the lower will be the amount of the increase actually received in the test year. In simple terms, if an annual increase of $80 million had been awarded after one-half of the 2009 test year had passed (which is the earliest that the interim increase

[1] The Stipulated Settlement Letter filed by the Parties on May 15, 2009 proposed an interim rate increase of $79,820,000. Hawaiian Electric corrected that amount to $79,811,000 in its

could have been made effective), then only approximately one-half of the increase (or $40.0 million) would actually be received in 2009. If an annual increase of $60 million is allowed after seven months, then only about $25 million would actually be received in 2009, which is less than one-third of the $80 million amount.

Q. What is Hawaiian Electric's position on whether the Company should be allowed to recover the amounts excluded from the interim rate relief?

A. Hawaiian Electric's position is that the Commission should approve recovery of those costs. Hawaiian Electric's supplemental testimonies support the interim rate relief amount reflected in its Statement of Probable Entitlement. In the section below, I emphasize that timely cost recovery is absolutely critical to Hawaiian Electric and that delays in the recovery of prudently incurred costs could damage the Company's financial condition and ability to obtain capital in the financial markets and ultimately hurt customers through higher rates and degraded service.

Q. How will Hawaiian Electric address recovery of the items that the ID&O excluded from interim rate relief?

A. To recover the amount excluded from the interim rate relief, Hawaiian Electric is considering two alternatives:

- Request the Commission to issue a second interim decision and order, subsequent to the evidentiary hearings for this proceeding (to begin the week of October 26, 2009), to approve the interim rate relief of

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Statement of Probable Entitlement filed on May 18, 2009.

$79,811,000 over current effective rates (i.e., an additional $18,713,000) that the Company requested in its Statement of Probable Entitlement, to be effective upon issuance of the second interim decision and order. If the Commission is not inclined to approve this entire amount, the Company would respectfully request the Commission to approve the interim rate relief attributable to the CIP CT-1 unit.

- Request the Commission to allow it to continue to accumulate allowance for funds used during construction ("AFUDC") on CIP CT-1 until the effective date of rates that recover the cost of the new unit. This would compensate the Company for the carrying cost of CIP CT-1 until the commencement of rate recovery. Ms. Patsy Nanbu discusses the accounting treatment of this alternative in HECO ST-11.

Q. Is there precedent for issuing a second interim decision and order in a rate proceeding?

A. Yes. In Docket No. 7000, the Commission approved (1) a general interim increase for a normalized 1993 test year by Interim Decision and Order No. 12163, issued January 29, 1993, (2) an interim Maalaea Unit 16 step increase (based on 100% of the cost of the unit) for the Maui Division by Interim Decision and Order No. 12378, issued May 7, 1993, following a motion filed April 23, 1993, and (3) an interim Maalaea Unit 15 step increase (based on 100% of the cost of the unit) for the Maui Division by Interim Decision and Order No. 12774, issued October 21, 1993 (which noted that a further motion was not necessary).

In Docket No. 7764, the Commission approved a general interim rate increase at the beginning of a 1995 test year by Interim Decision and Order No. 13716, issued December 30, 1994, and a further interim increase for the Waiau-CIP Transmission Lines (based on 100% of the cost of the lines) by Interim Decision and Order No. 14195, issued August 30, 1995. The first phase went into service on June 30, 1995 and the second phase went into service on August 15, 1995. In Interim Decision and Order No. 13716 issued at the end of the prior year, the Commission deferred consideration of the proposed step increases for the two phases of the project in light of doubts expressed by the Consumer Advocate as to whether the projects could be completed in 1995. Thus, HECO filed a motion to implement the steps on July 27, 1995, when it was clear that the lines would be operational.

In Docket No. 99-0207, HELCO's 2000 test year rate increase, the Commission approved a general interim rate increase by Interim Decision and Order No. 18008, issued September 1, 2000, and an interim Hamakua Energy Partners (HEP) step increase (based on the full cost of the power purchase arrangement) by Interim Decision and Order No. 18296, issued January 5, 2001 after HEP began commercial operations at the end of 2000.

There have been earlier cases as well, as identified in HECO T-1, pages 15-16, in support of the proposed CIP CT-1 step increase.

Q. Are there other alternatives to enable the Company to recover the amounts excluded from the interim rate relief?

A. Yes. As the Company proposed in its direct testimonies, there could be a step increase to recover the full cost of CIP CT-1, to be effective on the in-service date of the new unit. (See HECO T-1, pages 12-20.) However, the direct testimonies of the Consumer Advocate and the DOD both opposed a step increase for CIP CT-1.

Second, the excluded costs could be recovered through a surcharge mechanism such as the REIP/CEI Surcharge. However, the costs would need to comply with the conditions in the proposed REIP Framework. Also, due to concerns expressed by the Consumer Advocate in CA-T-1 about recovering labor costs through REIP/CEI Surcharge, Hawaiian Electric agreed in the Stipulated Settlement Letter (pages 89-90) that its labor costs are to be recovered solely through base rates and not through future REIP/CEI Surcharges that may be requested.

Third, the excluded costs could be deferred and recorded in a regulatory asset for recovery in a future rate case. This alternative would likely not be acceptable to the Company unless interest could be applied to compensate the Company for the delay in recovery.

Hawaiian Electric would be willing to discuss these alternative measures with the other Parties and the Commission.

<u>THE NEED FOR TIMELY COST RECOVERY</u>

Q. Please explain the Company's general concern with the exclusions ordered by the ID&O.

A. The Company's general concern is that the ID&O will delay or preclude the recovery of costs that Hawaiian Electric will prudently incur in the 2009 test year. As the other witnesses and I will explain in greater detail, the ID&O denies recovery, at least for interim purposes, of a substantial investment in a new generating unit, the need for which the Company has demonstrated in a lengthy proceeding that took two years to litigate and a number of reports and plans filed with the Commission. It also denies recovery of costs for positions that are absolutely essential to achieve State energy objectives and the initiatives codified in the Energy Agreement. These are largely positions for which employees have already been hired and are working on not only Energy Agreement initiatives but also other needed functions in the Company.

Q. Was there reason to conclude that Hawaiian Electric was probably entitled to an interim rate increase of $79,811,000, as proposed in its Statement of Probable Entitlement?

A. Yes. The Hawaiian Electric 2009 test year rate case was a complex rate case involving the addition of a new generating unit and the mid-stream addition of the obligations brought about by the Energy Agreement and impacts due to declining sales and economic recession. As a result, the Consumer Advocate and the DOD conducted extensive discovery on the Company's rate case filings that lasted nine months. The discovery period began when the Consumer Advocate submitted its first information requests on July 7, 2008, and ended when the Company submitted its last responses to information requests on April 3, 2009. The Consumer Advocate issued 504 information requests and the DOD issued 133. Because the information requests frequently had subparts, the total number of questions was much higher than the 637 information requests that the Consumer Advocate and the DOD submitted. Thus, the other Parties very thoroughly reviewed Hawaiian Electric's rate request. In the end, the Parties settled on all but two issues in this rate case and the resulting proposed interim increase amount of $79,811,000 was uncontested. In prior Hawaiian Electric rate cases that I am aware of, the amount of the approved interim increase has been at least equal to, but not limited to, the uncontested amount.

Q. Does the Company mean that the Commission should abstain from separately reviewing utility rate cases that have been settled with the other parties in the proceeding?

A. Absolutely, not. It is the Commission's prerogative to inquire into utility rate cases. However, there needs to be some balance to consider the potential impacts to the Company and ultimately to its customers if the Company will not be able to timely recover its costs. The fact that the other Parties heavily scrutinized the Company's rate request and were satisfied with the terms of the settlement agreement should provide confidence to the Commission that the Company is probably entitled to the settled amount for interim purposes.

Q. Please describe the impacts to Hawaiian Electric of not being able to timely recover its costs.

A. As Ms. Sekimura (HECO T-20) and Mr. Fetter (HECO T-21, HECO ST-21) explained, the prospect of not being able to timely recover its costs can have a damaging effect on the Company's ability to secure capital in the financial markets. A lack of regulatory support can cause credit rating downgrades, resulting in higher interest rates and an inability to obtain debt financing.

Q. Has the Company received feedback from the credit rating agencies on the ID&O?

A. Yes. There has been some feedback so far but there will possibly be more definitive reactions later. In a July 15, 2009 telephone conference, Standard and Poor's asked when the Company might get the "excluded" items back and noted the "gap" between the in-service date of CT-1 and its cost recovery. There was a huge concern with CT-1, with a large capital investment that will be placed in service real soon without any certainty of cost recovery. The CT-1 issue elevated S&P's concern because it is a fundamental investment whose application was already approved.

In a July 13, 2009 telephone conference, Moody's asked whether the Company would have to wait until a final decision in order to begin recovery for the large CT-1 investment and stated that the Company is working on a lot of "good" things, but noted that the economy is impacting our business and there is much regulatory uncertainty.

The Company will submit to the Commission and the Parties relevant releases from credit rating agencies as they occur.

Q. How will untimely cost recovery impact the Company's customers?

A. Untimely cost recovery may seem to benefit customers because of the delay in rate increases. However, the "benefit" is temporary. A utility cannot be expected to invest in infrastructure or expend dollars to initiate new programs or adequately maintain its equipment and facilities if it is unable to timely recover those costs. Investors will not be willing to contribute funds to invest in the Company's capital projects and there will be a drain on the Company's ability to finance on-going costs. In today's age of rapidly changing economic conditions, bankruptcies of utility companies are no longer unheard of. Ultimately, the deterioration in the Company's financial condition would have a material impact on the reliability and quality of service to customers.

Further, downgrades in the Company's credit ratings would result in higher interest rates that the Company would be required to pay for debt financing and these higher costs of capital would increase rates to customers.

Q. Is timely cost recovery needed from a ratemaking standpoint?

A. Yes. It is a fundamental principle of the ratemaking structure codified in State law and the Commission's rules. Section 269-16 of the Hawaii Revised Statutes ("HRS") calls for the issuance of decisions on rate proceedings as expeditiously as possible and before nine months from the date the public utility filed its completed application. It also requires that public utilities be provided the opportunity to earn a fair return on property actually used or useful for public utility purposes. Untimely recovery of costs will result in the utility not being able to earn a fair return on its property because it will not be able to generate sufficient revenues to cover its operating costs and still provide a fair return to investors.

Section 6-61-87 of the Hawaii Administrative Rules ("HAR") requires a forward test year which conceptually has the effect of more closely matching the rates in effect (i.e., cost recovery) with the costs expected to be incurred, thereby reducing regulatory lag and effecting more timely cost recovery. However, these effects are negated if costs expected to be incurred in the test year are not approved into rates or if there is a delay in such approval.

Paragraph 2.3.g.2. of General Order No. 7 requires the utility to file an application for proposed capital expenditures for any single project in excess of $2.5 million at least 60 days prior to the commencement of construction or commitment for expenditure, whichever is earlier. If the Commission determines, after hearing, that any portion of the project is in excess of probable future requirements for utility purposes, the utility shall not include such portion in its rate base. If the utility subsequently convinces the Commission that the property has become necessary or useful for public utility purposes, it may be included in rate base. Failure of the Commission to render a decision and order within 90 days of the filing allows the utility to include the project in its rate base without the determination by the Commission. Although in practice, the costs of such projects are not rolled into rates until the next rate case, it is clear that this rule was intended to keep timely the decision making process to include (or exclude) major capital projects in rate base.

Mr. Steven Fetter in HECO ST-21 explains that timely recovery of actual costs with a fair return should be a regulatory goal – it is consistent with the regulatory compact (which I describe later) and works to minimize regulatory lag which financially injures a regulatory utility with no real remedial recourse.

CAMPBELL INDUSTRIAL PARK CT-1

Q. What rationale does the ID&O provide to exclude the costs of the CIP CT-1 from interim rate relief?

A. The ID&O states the following:

> The commission is concerned that HECO's CT-1 unit is not currently "used and useful." To allow HECO to recover costs associated with CT-1 as of July 2009, prior to it becoming "used and useful" is inappropriate and inconsistent with Decision and Order No. 23457, filed on May 23, 2007. In addition, the commission is concerned that CT-1 may not be operational by the end of the 2009 test year because the fuel supply contract has not been resolved. The record is currently insufficient to demonstrate that the CT-1 unit will be in service by the end of the 2009 test year.
>
> Consequently, the commission denies the inclusion of any costs or rate base additions associated with the CT-1 unit in interim rates…

If this provision means that the CIP CT-1 costs cannot be rolled into interim rates until it is "currently" used and useful, it would be inconsistent with the forward test year principle in HAR 6-61-87 which contemplates rates being based on projections of future cost.

In HECO ST-21, Mr. Fetter states that matching up forecasted costs with timely and full recovery, or refund if appropriate, is consistent with the ".."

Q. Please explain the concept of the "regulatory compact."

A. The Hawaii PUC has described the "long-standing regulatory compact" as follows:

> The regulatory compact has two aspects: (1) in return for a monopoly franchise, utilities accept the obligation to serve all comers; and (2) in return for agreeing to commit capital necessary to allow the utilities to meet the obligation, utilities are assured a fair opportunity to earn a reasonable return on the capital prudently committed to the business. In Wash. Util. And Trans. Comm'n v. Puget Sound Power & Light Co., 62 P.U.R.4th 557, 581 (1984), the Washington Commission explained the regulatory compact in this fashion:
>
> "The social and economic compact of utility regulation begins with the premise that a regulated utility has an obligation to serve the public. [A] utility possesses an unending obligation to provide service to anyone within the service territory of that utility who demands service in accordance with approved tariffs.
>
> However, in order for the social duty to serve to be viable, the compact must also provide for a utility to recover expenses it prudently undertakes to meet the obligation. (Emphasis original.)"

Re Citizens Utilities Company, Kauai Electric Division, Docket Nos. 94-0097 & 94-0308, Decision and Order No. 14859 (August 7, 1996), page 13.

Q. How does the regulatory compact apply to ratemaking?

A. It is essential and in the public interest (that is, in the interests both of the stockholders and the ratepayers) that public utilities be permitted to charge rates which cover all of their reasonable costs of providing service, including their costs of capital. The reason, of course, is that if a utility's rates do not provide it with sufficient revenues to cover its cost of providing service, then some aspect of its service will suffer. If the utility cannot earn its authorized fair rate of return, then, by this Commission's definition of a fair return, the utility will not be able to attract the capital necessary to replace plant and equipment at reasonable rates, upgrade service where appropriate or add new plant and equipment to meet its obligation to serve all customers new and old alike.

The fundamental tenet of ratemaking that rates must cover the costs of providing service is well known. The basic question in a rate case (apart from rate structure issues) is how to set rates for the future that will provide the utility with a real opportunity to receive revenues that cover its operating expenses plus its cost of capital.

In the rate case process, the bottom line should be whether the end result meets the goal of ratemaking. If the goal is not met, then it would seem that steps should be taken by all parties concerned to improve the process or the public interest has not been adequately served. By way of example, if a reasonable operating expense is understated or disallowed in the Commission's final decision and order because the Company failed to adequately prove its projection or explain the reason for the expense, or because there was a misunderstanding of the evidence presented or methodologies adopted were incorrect and which the Company has not had the opportunity to address by way of evidence, the result is the same the rates will probably not cover the Company's cost of providing service and the public's interest in fully compensatory rates will not have been served. Thus, it is important that all parties fully understand the nature of the proof required by the Commission. Moreover, the proof required must not be unduly burdensome or the entire ratemaking process will collapse from the resulting paper avalanche.

Q. Can the Commission find that estimated plant in service is "used and useful" for public utility purposes?

A. Yes. The Hawaii Supreme court explicitly affirmed the Commission's finding that a utility's plant-in-service was "used and useful" for public utility purposes where its 1976 rate was based on its 1975 year-end balances and an estimated plant additions for 1976 using the utility's capital budget estimates. See, In re Hawaiian Telephone Company, 49 P.U.R. 4th 139, 65 Haw. 293, 651 P.2d 475 (1982).

In re Hawaiian Telephone Company, the Commission accepted the estimated additions for 1976 prepared by Hawaiian Telephone Company ("HTC") as evidence of the original cost of the company's physical property in telephone service. The final revised plant-in-service estimate that HTC submitted to the Commission included figures taken from HTC's plant-in-service accounts through December 31, 1975, plus estimated additions for 1976. After examining the evidence, the Commission concluded that HTC had established a prime facie case that its plant-in-service was used or useful for public utility purposes.

Q. Should property that services both current and future needs be included in rate base?

A. Yes. If a utility has taken prudent steps to meet the future needs of its customers in adding new plant it should be included rate base. There are numerous electric utility examples where the Commission approved projects that were installed in logically sized increments, and the entire cost of the project was included in rate base even though part of the capacity may not have been needed immediately.

The case of Re Hawaiian Electric Co., Docket No. 2296, Decision and Order No. 3546 (August 19, 1974) is instructive:

> The Staff proposed to disallow in the rate base one-half of the cost of Kahe Generating Unit No. 5, which is scheduled to go into commercial operation in November, 1974, on the grounds that it is excess capacity and will not actually be needed at that time because of the slower rate of growth due to the recent energy crisis. This proposal reduces the rate base by approximately $14,600,000. . . . HECO cited a number of court and commission decisions[1] indicating that commissions have included in the rate base excess capacity which has been prudently acquired and the use of which may be anticipated with reasonable precision, even though the plant would not actually be in service by the end of the test year. In the present case, Kahe 5 will actually be in service at the end of the test year. Under all the circumstances, the Commission is of the opinion that the full cost of Kahe 5 must be included in the rate base.
>
> [1] Baltimore Gas & Electric Co. v. People's Counsel, 220 Md. 373, 152 A.2d 825 (1959); Southern New England Tel Co. vs. Public Util. Comm'n, 29 Conn. Super. 253, 282 A.2d 915, 920 (1970); Re New Haven Water Co., 49 P.U.R. (N.S.) 229 (Conn. P.U.C. 1943); Re Consumers of Edison Electric Illuminating Co. of Boston, 5 P.U.R. (N.S.) 369 (Mass. Dept. of Pub. Util., 1943); Wisconsin Telephone Co. v. Public Service Commission, 30 P.U.R. (N.S.) 65, 287 N.W. 122 (S. Ct. Wis. 1939); Re Consolidated Edison Co. of N.Y., 54 P.U.R. 3d (N.Y. Comm 1968); Latourneau v. Citizens Utilities Co., 59 P.U.R. 3d 1, 209 A.2d 307 (Vt. S. Ct. 1965).

Id. 5-6.

Both the Idaho and the Connecticut cases cited in the footnote quoted the following language from 73 C.J.S. Public Utilities §18 (at 1017):

> On the other hand, property or equipment provided or acquired in anticipation of reasonable future need should be allowed as part of the rate base even though wholly or partially unused at the time to which the inquiry relates.

Idaho Underground Water Users Association, 404 P.2d 859, 867 (1965); Southern New England Telephone Co., 282 A.2d at 919-20.[2]

The Commission reached the same conclusion that it had reached in its 1994 HECO decision in Re Hawaii Electric Light Co., 13 P.U.R. 4th 329 (1976):

> Another major difference between the parties was the inclusion in the rate base of the depreciated cost of certain generating plant. The division excluded from the rate base 50 per cent of the depreciated cost of 26 megawatts of generating plant it contended was "least used." Lima Kokua contended that depreciated cost of the 23-megawatt generation plant known as Hill 6, HELCO's newest plant addition should be removed from the rate base.

Id. 336-37. The Commission rejected the contentions of both the Public Utilities Division ("PUD," now the Consumer Advocate) and Lima Kokua, both of which were predicated on claims that HELCO had excess capacity after adding new generation, because load growth had not materialized due to the "energy crisis." Id. 337. With respect to the PUD's contention, the Commission concluded:

> After reviewing the evidence in the record on this point, the Commission concludes that these generating units, or so-called "least-used plant", are not excess but were prudently added to the system and are actually used and useful and will be used in the future. Consequently, it appears reasonable that such plant is used and useful for utility purposes within the meaning of §269-16(a) of the Hawaii Revised Statutes and, therefore, has to be included in the rate base.

[2] The Connecticut case involved land, but the Idaho case concerned a generating facility.

The common theme in these cases is that (1) the utility had taken prudent steps to meet the future needs of its customers in adding new plant, (2) the plant was actually being used, and (3) the challenged plant will be used in the future.

Q. Are these decisions by the Hawaii Commission consistent with other jurisdictions?

A. Yes. The holdings in these Hawaii Commission cases are consistent with the holdings in cases from other jurisdictions.

In Re Pacific Power & Light Co., 63 P.U.R. 4th 642 (Ore. PUC 1984), intervenors recommended that Pacific Power & Light Co.'s ("PP&L") coal fire generating facility ("Colstrip Unit 3") be removed from its rate base. Intervenors contended, among other things, that (1) Colstrip Unit 3 was not used and useful because the plant had been placed in service during a period of surplus capacity (2) Colstrip Unit 3 was not an economical resource, and (3) prudent resource planning would have resulted in a deferral of Colstrip Unit 3 construction. Id. 645.

The Oregon Public Utility Commissioner ("PUC") held that (1) despite the utility's existing surplus, Coltrip Unit 3 was presently used to provide electric service to Oregon customers and was useful to ratepayers in a number of respects, id.,[3] (2) the appropriate focus of inquiry was not whether Colstrip Unit 3 was the most economical resource, but whether the utility's decision to

[3] Colstrip Unit 3 was found to be useful because it (1) could displace other generating plants with higher variable costs, (2) improved existing system reliability in the event of generating unit

proceed with construction was prudent at the time it was made, id. 647 and (3) PP&L's actions, including its decision to complete Colstrip Unit 3, were reasonable and prudent, and that intervenors' claims that Colstrip Unit 3 could have been economically deferred and that PP&L continued construction of Colstrip Unit 3 despite knowledge of a surplus were unsubstantiated, id. 647-48.

In addition, the Oregon PUC held that exclusion of the Colstrip Unit 3 from rate base because it had come on line during an energy surplus would be unsound from a regulatory policy standpoint:

> Specifically, the argument ignores not only the public service obligation of utilities, but also the realities of resource planning and the adverse financial consequences that would inevitably ensure for the utility and its ratepayers.
>
> Under current economic conditions, the time necessary to complete construction of a major generating facility ranges from six to twelve years. If the on-line date of a plant happened to coincide with an energy surplus, the project would assign all cost responsibility to the utility's shareholders, regardless of whether the original decision to construct the plant was reasonable and prudent. This approach to rate making would have extremely undesirable consequences. The risk of holding utility securities would increase substantially, reducing stock prices and bond ratings, and resulting in much higher capital costs. The likelihood of energy shortages would also increase because of the reluctance of utility management to assume absolute responsibility for the timing of new generating facilities. Under either scenario, the impact upon customers would be the same – higher utility rates because of an unstable regulatory environment.

Pacific Power & Light, 63 P.U.R. 4th at 645-46.

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failures or unforeseen system load growth, and (3) allowed for greater flexibility in maintenance scheduling and energy dispatching.

In a District of Columbia Public Service Commission ("D.C. PSC") case, the D.C. PSC declined to adopt the Office of the People's Counsel ("OPC") proposed disallowance of Chesapeake and Potomac Telephone Co.'s ("C&P") investment in fiber optics. OPC contended that C&P had overinvested in fiber optics, and the bulk of the installed fiber plant had not yet been activated. The D.C. PSC concurred with C&P, and held that C&P should be encouraged and not penalized for modernizing its network, planning for future needs, and providing for route diversity and network survivability. <u>Chesapeake and Potomac Telephone Co.</u>, 130 P.U.R. 4th 310, 342-44 (D.C. P.S.C. 1992), <u>modified</u>, <u>Re Chesapeake & Potomac Telephone Co.</u>, No. 850, Order No. 9983, slip. op. (D.C. P.S.C. March 6, 1992).

Q. The ID&O states that the CIP CT-1 may not be operational by the end of the 2009 test year because the fuel supply contract has not been resolved. Does the commercial operation of the CIP CT-1 depend on the use of biofuel?

A. As Mr. Simmons explains in HECO ST-17E, it does not. Hawaiian Electric is committed to living up to the agreement between the Company and the Consumer Advocate in Docket No. 05-0145 to fuel the new unit using 100% biofuel. However, the new unit is currently permitted to burn petroleum diesel and will be seeking the necessary permit modifications to allow the use of biofuel in the new unit. Mr. Simmons explains that if the Commission denies approval of the proposed biofuel contracts in the Imperium proceeding (Docket No. 2007-0346), the Company intends, in the meantime, to operate the new unit under the provisions of its existing air permit to ensure the reliability of electrical service to its customers.

Q. Is the in-service date of the Campbell Industrial Park Generating Station still July 31, 2009?

A. Yes, it is. As Mr. Robert Isler states in HECO ST-17A, this means that the combustion turbine-generator will be tied into the electrical grid and producing power.

Q. What amount of CIP CT-1 plant additions is included in rate base in the Company's Statement of Probable Entitlement?

A. As shown in the Supplemental Testimony of Ms. Lorie Ann Nagata, HECO ST-17, the amount of CIP CT-1 plant additions in the Company's proposed rate base is $83,769,731. This corresponds to an estimated project cost of $163,279,651, as shown in HECO-S-1701. The amount in rate base is substantially lower because the Consumer Advocate and the DOD rejected the Company's step increase proposal to include the full cost of the CIP CT-1 in rate base. Instead the Parties agreed for the purposes of settlement to reflect an average rate base amount for the CIP CT-1 in the 2009 test year revenue requirement. In effect only one-half of the 2009 CIP CT-1 plant additions estimated amount is included in rate base.

Q. The Company recently filed a cost report in Docket No. 05-0145 showing an increase in the CIP CT-1 project to $193 million. How does the Company intend to recover the balance of the CIP CT-1 investment?

A. As stated on page 88 of Exhibit 1 of the Stipulated Settlement Letter in this proceeding: "Based on the joint decoupling proposal of the Company and the Consumer Advocate in the decoupling docket, which incorporates a RAM rate base adjustment in 2010 that includes actual year-end 2009 plant balances (as well as conservatively estimated plant additions in 2010), HECO (as part of the global settlement agreement) has agreed to the use of the fully average test year, without a separate CIP CT-1 Step Increase or annualized ratemaking treatment of CIP CT-1 costs."

Q. Has the Company explained the reasons for the increase in the CIP CT-1 project costs?

A. Yes. On May 6, 2009, the Company filed Cost Estimate Update for CIP CT-1. Mr. Isler and Mr. Lunardini also explain the reasons for the cost increase in their supplemental testimonies, HECO ST-17A and HECO ST-17B.

Q. For the purposes of this rate case, the rate base amount for the CIP CT-1 is now based on the lower project cost of $163,279,651. Should this amount be adjusted to reflect the updated current cost estimate, given the testimony now presented on that point?

A. We have not proposed that, since the update was filed in May, the stipulated interim that included the cost of the unit was expected to be effective at the beginning of July, the hearing was scheduled for August, and the joint decoupling proposal with the Consumer Advocate would allow for a RAM adjustment reflecting the full cost of the unit in January 2010. The circumstances have changed. If the interim increase is adjusted to reflect the rate case estimate for CT-1 after the unit goes into service, however, then it would still be appropriate for the increase to reflect the current "rate case" estimate of $163,279,651.

Q. Page 19 of the IDO provides that:

> Rate Base Calculation Methodologies: Page 64 of Exhibit 1 of the Settlement Agreement describes how the rate base has been calculated by averaging the 2008 year-end rate base and the expected 2009 year-end rate base. The commission notes that an alternative methodology for calculating the rate base is to use the thirteen-month final balances from the month preceding the test year through the end of the test year. This method gives less weight to capital additions made at the end of the test year, which the CT-1 unit is likely to be. The commission asks the Parties to file testimony by July 20, 2009 examining whether averaging the rate base at the beginning and end of the test year is appropriate or whether HECO should employ other methodologies, such as thirteen-month averages, to calculate the rate base.

What is Hawaiian Electric's response?

A. The simple average rate base is the standard in Hawaii, and has been used in rate cases going back at least 30 years. There was a period in the 1970's and 1980's when a year-end rate base was used with an average test year in order to provide some offset to the effects of attrition caused by external factors such as high inflation or regulatory lag. (See Hawaiian Tel D&O 8711, issued April 4, 1986; HELCO D&O 7553, issued May 27, 1983; MECO D&O 6953, issued January 15, 1982; HECO D&O 4802, issued August 18, 1977.) It has not been used since due to the known inconsistency with the "matching" principle in rate-making, i.e., measuring revenues, expenses, and rate base over the same time period and under similar conditions in order to determine revenue requirements.

The use of thirteen-month averages is referred to as a weighted average rate base. It is easier to use in the case of an historic test year, since the exact timing of plant additions is known.

The rate base results using a simple average rate base and a weighted average rate base may differ in the case of large capital additions. This has not necessarily been a problem in prior rate cases, where the costs associated with large plant additions were included in step increases, which can more precisely time cost recovery for such additions with the in-service dates for the units.

In this case, there was certainly no "unfairness" in the "end result" to ratepayers in the use of an average rate base, even though most of the project was not scheduled to be in service until the end of July, since the interim rates incorporating the test year results would not go into effect until the beginning of July (rather than the beginning of the test year). The 2009 plant addition amount for the CIP CT-1 projects that was included in rate base was about $153 million (i.e., $164 million minus $11 million). See HECO-1703. The annual revenue requirements associated with one-half of that amount are about $12 million, but only one-half of that amount, or about $6 million, would be collected in 2009 with a July interim. The annual revenue requirement associated with five-twelve's of that amount is about $5 million. In 2010, the revenue requirements for the 2009 capital addition would be based on the entire cost of the addition, plus depreciation. Thus, the amount included in rates for the capital addition based on a 2009 test year using either the simple-average or weighted-average rate base would be insufficient. The amount recovered with a step increase effective August 1st based on the full cost would also recover about $10 million in 2009 (i.e., the same amount as the weighted-average rate base method), but would come closer to recovering the 2010 revenue requirements in 2010 than the other methods.

HCEI-RELATED POSITIONS

Q. What does the ID&O state with respect to "HCEI-related positions"?

A. The ID&O states the following:

> In Rate Case Update HECO T-15 (pages 4-11), HECO identified several positions that were created due to the various proposed HCEI initiatives, including the PV Host Program, FIT, the Lifeline Rate Program, decoupling, demand response programs identified in the Energy Agreement, the "Big Wind" project, AMI, and CESP. The commission has not approved these programs nor determined that their costs are just and reasonable. Accordingly, the commission requires that HECO exclude the costs associated with these positions from interim rates…

Q. The ID&O also referred to an April 6, 2009 letter regarding excluding from the Statement of Probable Entitlement any mechanisms or expenses related to programs or applications that have not been approved by the Commission (e.g., decoupling, Renewable Energy Infrastructure Program, Solar Saver Pilot Program amendments, Advanced Metering Infrastructure Program). Please provide your comments on this matter.

A. At the outset, it is clear that our use of the term "HCEI" as often as we do is a mistake on our part. When we received the April 6, 2009 letter from the Commission, we should have adjusted our terminology to differentiate activities which are not "new" (i.e., HCEI-related) from those which are part of ongoing Commission inititives. We did not do so and clearly gave the Commission the sense that we ignored its April 6, 2009 letter. This was not our intent and I apologize for any confusion that we caused in this area.

One key area of new employees is the power purchase area. The Commission has made clear the last few years, and especially in the last year, that it expected us to sign more power purchase agreements ("PPAs") and expand renewable energy generation. Historically, our PPA area was responsible to manage all existing contracts (e.g., Kalaeloa, AES and H-Power) and to sign up new PPAs. In order to accelerate PPAs we decided to split the PPA area into two, one to handle the on-going contract administration issues and the other to negotiate new PPAs. We do not view this as a new HCEI-related activity. Instead, we view this as a Commission-initiated activity. Of the so-called HCEI positions, three of the nine positions relate to this PPA function and are not HCEI-related positions.

The new positions include a position Customer Solutions to advance the level of demand response or load management. In the Commission's decision in the energy efficiency proceeding in which the decision was made to go with a third-party administrator, the load management programs were left with the Company. While the Energy Agreement emphasized the system value of demand response, our obligations to an aggressive load management program flows not from HCEI but from the earlier Commission decision.

The new positions include two senior technical services engineers. While our filing says that they will help with the PV Host program, they will also perform other services in the distributed generation area, particularly with the military initiatives.

Q. Do the Hawaii Clean Energy Initiative and the Energy Agreement between Hawaiian Electric and the State of Hawaii represent a new energy policy for Hawaii.

A. As I explained in my rebuttal testimony, Hawaii energy policy has supported and continues to strongly support (1) increased energy self-sufficiency, (2) greater energy security in the face of threats to Hawaii's energy supplies and systems; and (3) reduction, avoidance, or sequestration of greenhouse gas emissions from energy supply and use, as well as (4) dependable, efficient, and economical statewide energy systems capable of supporting the needs of the people. The HCEI does, however, represent a substantial commitment to strongly accelerate the pace at which the first three objectives are obtained.

The Energy Agreement includes references to much of the Hawaiian Electric Companies' on-going renewable energy and energy efficiency efforts (such as Hawaiian Electric's Renewable Energy RFP), as well as new commitments made by the Companies in the Agreement. Many of the on-going efforts were initiated under the auspices of Commission polices. The Energy Agreement was used as a platform to reflect existing decisions, agreements and programs, as well as to document new commitments by the parties.

Q. Can Hawaiian Electric prudently wait before incurring costs to meet the objectives in the Energy Agreement?

A. No. Our job as a utility is to plan how we are going to meet the accelerated obligations, which are already embedded in State law as a result of Act 155. Act 155 increases the electric utilities' 2020 RPS requirement from 20% to 25%, and adds a new 40% requirement for the year 2030. Prior to January 1, 2015, at least 50% of a utility's RPS must be met by "electrical generation using renewable energy as the source". After January 1, 2015, however, a utility's entire RPS will need to be met by renewable generation, and "electrical energy savings" will no longer count toward RPS requirements.

Moreover, with or without the new RPS requirements, we needed to add staff to deal with the numerous renewable power purchase opportunities with which we have been presented (due as much to the oil price spike experienced last summer, as to the HCE initiative), and the challenges presented by having to integrate large amounts of intermittent renewable energy resources into isolated island grids.

Q. What has Hawaiian Electric done to justify the additional staff positions?

A. The need for the new positions was fully explained and justified in the updates we filed in December 2008, and was further scrutinized by the Consumer Advocate and the DOD through the formal (information requests) and informal (meetings) discovery process. It is appropriate for the costs of these positions to be included in the interim rate relief and in the final revenue requirements for the 2009 test year.

Q. Has the Commission's review and approval role been bypassed?

A. No. The Commission initiated decoupling and feed-in tariff proceedings, and the utilities will not be able to implement decoupling or feed-in tariffs until authorized to do so by the Commission. Other implementation items also will require specific Commission approval, such as the approvals that have been or will be requested for the Advanced Metering Infrastructure ("AMI") project, power purchase agreements, and renewable energy infrastructure projects.

Q. Should the Commission allow inclusion of the costs of these positions in the 2009 test year.

A. Yes, definitely. These positions are necessary for the transition of Hawaii to a renewable energy future as reflected in State law and for other utility purposes. Therefore, their associated costs are reasonable for inclusion in the 2009 test year.

MERIT EMPLOYEE WAGE INCREASE

Q. What adjustment did the ID&O order for merit employee wage increases?

A. The ID&O states the following:

> The commission finds that the record insufficiently addresses the accuracy, reasonableness, and fairness of the proposed wage increases for merit employees given current economic conditions. For purposes of interim rates, wage levels are restricted to 2007 levels or the most recent actual labor costs filed with the commission, taking into account the vacancy rate agreed upon by the Parties on pages 22 and 23 of the Settlement Agreement…

Q. Did Hawaiian Electric reduce its merit wage increase amount in the 2009 test year prior to the issuance of the ID&O?

A. Yes. Page 25 of Exhibit 1 of the Stipulated Settlement Letter stated that given the current economic environment, and in the interest of reaching a global settlement in this proceeding, the Company proposed to lower the O&M labor expenses for merit employees for 2009 by $532,000. The Consumer Advocate and the DOD agreed to the reduction.

Q. Do current economic conditions warrant lower wages than those agreed to by the Parties in the Stipulated Settlement Letter?

A. No. As Ms. Furuta-Okayama explains in HECO ST-15A, Hawaiian Electric evaluates available survey data as well as pay increases in the bargaining unit contract, Company financial performance and other information to develop the Company's merit wage budget. The survey data indicate that the merit wage increase to which the Parties agreed in this proceeding is in line with wage increases of other employers in Hawaii and the United States in 2009. Therefore, the Commission should accept the merit wage increase reflected in the Stipulated Settlement Letter and the Statement of Probable Entitlement.

Q. Are there other reasons why the merit salaries should not be lowered below that level?

A. Yes. Reducing salaries further may put the Company's ability to retain its most experienced and strongest performing employees at risk and would reduce the Company's ability to attract qualified candidates. Increased turnover will hamper productivity and increase costs of recruitment efforts.

Q. In light of the current economic downturn in Hawaii and nationally, has the Company considered measures to contain and cut costs?

A. Yes. Hawaiian Electric continually reviews its expenses, reassesses priority items and takes advantage of savings opportunities. However, particularly now, given negative economic conditions, even greater emphasis is placed on reducing costs wherever possible and increasing efficiencies and savings.

Q. Please provide examples of these cost-containment and savings efforts.

A. The Company has been undergoing reviews of existing contracts to find opportunities to renegotiate or otherwise modify agreements with vendors. For example, we are currently renegotiating a contract for wood poles and may arrange to have wood poles on consignment.

Also, based on discussions between Hawaiian Electric and outside consultant Black and Veach, the consultant has proposed volume-based discounts of up to twenty percent for new services by its Energy Division.

Further savings come from ABB, Inc., which has offered price decreases for distribution transformers to be shipped to Hawaiian Electric in the third quarter of 2009. These lower prices are on top of decreases in the first and second quarters of 2009.

Q. Has Hawaiian Electric also examined possible savings in administrative costs?

A. Yes. Contracts with office supply vendors are currently being reviewed to potentially reduce their offerings to generic products. In addition, we are working with our major wireless phone service providers, AT&T Wireless and Verizon Wireless, to re-evaluate the Company's rate plans with them. In this effort, we are coordinating with Hawaiian Electric Industries and American Savings Bank to seek price discounts on an even larger scale across our affiliated companies.

These are just a few of the cost-containment actions being taken throughout the Company at this time.

EMPLOYEE ELECTRICITY RATE DISCOUNT

Q. Is Hawaiian Electric proposing any changes to its proposed Schedule E, Electric Service for Employees, in this rate case?

A. Hawaiian Electric has not proposed any change to Schedule E. Schedule E provides that the rates applicable to residential service for Hawaiian Electric's employees are two-thirds of the rates specified under Schedule R, for usage up to 825 kwh per month. Energy usage above 825 kwh is subject to the full Schedule R energy rates. The employee discount has been in effect for over 50 years.[4]

Q. What does the ID&O require regarding Schedule E?

A. The ID&O states that for the purposes of interim rates, the Commission directs HECO to remove Schedule E and adjust other rates based on this change. Hawaiian Electric requests the Commission to allow the Company to retain Schedule E in its current form.

Q. Why does Hawaiian Electric offer an employee discount?

A. The employee discount is a mechanism by which the Company can compensate its employees with minimal tax consequences. Generally, it would cost more in additional salary and/or benefits to replace the discount.

Q. Are employee discounts rare in Hawaii?

A. No. It is commonly known that many companies in Hawaii provide some form of employee discounts.

Q. Have employee discounts been previously examined and approved by the Commission?

A. Yes. In Re Hawaiian Electric. Co., Docket No. 3705, Decision and Order No. 6275 (July 9, 1980), at 15, the Commission specifically found that:

> The comparative analysis of HECO's employees and residential customers other than HECO's employees, made by the Consumer Advocate was insufficient for the Commission to conclude that in fact HECO's employees were not energy oriented in their consumption of electricity …. The Consumer Advocate had the burden of showing that the employee discount was unreasonable for the reasons it stated. There was inconclusive evidence on the part of the Consumer Advocate on this issue. If in fact, any future studies do show that the employees are wasteful in their energy use due to the discount, the Commission can reconsider this issue.

In Docket No. 6432, Decision and Order No. 10993 (March 6, 1991), at 154, the Commission stated:

> Employee discount has been an issue many times before. The commission has repeatedly rejected its elimination. We will adhere to our past decisions and reject its elimination in this docket. The employee discount has been negotiated in good faith between [Hawaii Electric Light Company, Inc.] and its employees. We are constrained from interfering with that agreement, although there is nothing that legally requires us to recognize the discount.

Q. If employee discounts are to be discontinued, is it preferable that it be terminated after the applicable collective bargaining agreements have expired?

A. Yes. The elimination of employee discounts which is part of the Collective

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[4] Company records indicate that the tariff for Electric Service for Utility Employees (then Schedule G) went into effect on June 1, 1955. The tariff stated that rates for this service

Bargaining Agreement between Hawaiian Electric and Local 1260 of the International Brotherhood of Electrical Workers, AFL-CIO ("IBEW") may create issues of compensation between the Company and the IBEW. See the supplemental testimony of Michael McInerny (HECO ST-15B).

Q. Is discontinuing employee discounts only after applicable collective bargaining agreements have expired consistent with other jursidctions?

A. Yes. In a Vermont case, Re Central Vermont Public Service Corp., 72 P.U.R. 4th 733, 766 (VT. PSB 1986), the Vermont Commission required the utility to study alternatives to the employee discount and to present the alternatives and a plan to phase the employee discount out in its next rate case.

In the case Central Main Power Co. v. Public Utilities Commission, 433 A.2d 331 (Me. 1981), the court affirmed an order of the Maine Commission that the utility submit a plan to phase out the employee discount by no later than a certain date. However, the court remanded the matter to the Commission to clarify whether it intended that the employee discount be phased out before or after expiration of the utility's collective bargaining agreement. Id. at 338.

In the case of Re Montana-Dakota Utilities Co., 72 P.U.R. 4th 467 (N.D. PSC 1986), the North Dakota Commission directed the Company, "when it negotiates a new labor agreement in 1987 [to] take the necessary steps to implement the discount level which will insure that all employees at least cover the cost of gas." Id. at 479.

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were two-thirds of the rates and charges specified under Schedule AC – Residential Service.

Q. What is Hawaiian Electric's position on the employee discount?

A. Hawaiian Electric requests the Commission to allow the Company to retain Schedule E in its current form. If the Commission decides that Schedule E should be permanently terminated, it should be done prospectively after collective bargaining agreements have expired.

Q. Does this conclude your testimony?

A. Yes, it does.

Witness HECO ST-1

has no supplemental exhibits.

SUPPLEMENTAL TESTIMONY OF
PETER C. YOUNG

DIRECTOR, PRICING DIVISION
ENERGY SERVICES DEPARTMENT
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Total Operating Revenue,
Including Electric Sales Revenue
and Other Operating Revenue

INTRODUCTION

Q. Please state your name and business address.

A. My name is Peter C. Young and my business address is 220 South King Street, Suite 1201, Honolulu, Hawaii.

Q. By whom are you employed and in what capacity?

A. I am director of the Pricing Division of the Energy Services Department at the Hawaiian Electric Company, Inc. ("HECO" or "Company"). My experience and background are listed in HECO-300. I have previously submitted direct testimony in this docket as HECO T-3 and HECO T-22. I am also submitting supplemental testimony as HECO ST-22.

Q. What is your area of responsibility in this supplemental testimony?

A. My testimony in HECO ST-3 will address Section IV.(a) of the Commission's *Interim Decision and Order* ("Interim D&O"), issued July 2, 2009 in this proceeding, regarding "Settlement Increase in Rates."

Q. What did the Interim D&O say relative to the settlement increase in rates?

A. The Interim D&O asked for a reconciliation of the proposed interim rate increase of $79,820,000 over current effective rates included in the introductory letter of the Settlement Agreement with the increase of $79,699,000 shown on page 8 of Exhibit 1 of the Settlement Agreement.

Q. How are the two amounts reconciled?

A. The increase of $79,820,000 over revenues at current effective rates included in the introductory letter of the Settlement Agreement reflects "Total Operating Revenues," while the amount of $79,699,000 shown on page 8 of Exhibit 1 of the Settlement Agreement reflects only the increase of "Electric Sales Revenues" over revenues at current effective rates. The difference of $121,000 between the Total

Operating Revenues of $79,820,000 and Electric Sales Revenues of $79,699,000 is the increase of the Company's "Other Operating Revenues" over revenues at current effective rates. Stated another way, the sum of "Electric Sales Revenues" of $79,699,000 and "Other Operating Revenues" of $121,000 equals the "Total Operating Revenues" of $79,820,000. The relationship between Electric Sales Revenues, Other Operating Revenues, and Total Operating Revenues is shown in HECO-S-301.

Q. Is the increase of $79,820,000 supported by narrative, exhibits, and references to the record in the Settlement Agreement?

A. Yes, the $79,820,000 is supported by narrative, exhibits, and references to the record in the Settlement Agreement on pages 4 through 11, in the sections titled "Electric Sales Revenues" and "Other Operating Revenues."

Q. Does this conclude your testimony?

A. Yes.

Hawaiian Electric Company, Inc.
Settlement at 10.5% at Curr Eff Rates
Results of Operations
2009
($ Thousands)

	Current Effective Rates	Additional Amount	Revenue Requirements to Produce 8.45% Return on Average Rate Base
Electric Sales Revenue	1,291,619	79,699	1,371,318
Other Operating Revenue	4,140	121	4,261
Gain on Sale of Land	615		615
TOTAL OPERATING REVENUES	1,296,374	79,820	1,376,194
Fuel	438,348		438,348
Purchased Power	346,467		346,467
Production	78,973		78,973
Transmission	13,859		13,859
Distribution	29,844		29,844
Customer Accounts	12,500		12,500
Allowance for Uncoll. Accounts	1,302	0	1,302
Customer Service	5,784		5,784
Administration & General	88,948		88,948
Operation and Maintenance	1,016,025	0	1,016,025
Depreciation & Amortization	81,868		81,868
Amortization of State ITC	(1,453)		(1,453)
Taxes Other Than Income	122,103	7,088	129,191
Interest on Customer Deposits	479		479
Income Taxes	15,914	28,299	44,213
TOTAL OPERATING EXPENSES	1,234,936	35,387	1,270,323
OPERATING INCOME	61,438	44,433	105,871
AVERAGE RATE BASE	1,253,601	(719)	1,252,882
RATE OF RETURN ON AVERAGE RATE BASE	4.90%		8.45%

SUPPLEMENTAL TESTIMONY OF

ROSS H. SAKUDA, P.E.

DIRECTOR
GENERATION PLANNING DIVISION
SYSTEM INTEGRATION DEPARTMENT
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Continued Need for Campbell Industrial Park CT-1 Projects

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Ross Sakuda and my business address is 820 Ward Avenue, Honolulu, Hawaii.

Q. By whom are you employed and in what capacity?

A. I am employed by Hawaiian Electric Company, Inc. ("Hawaiian Electric", "HECO", or "Company") as the Director of the Generation Planning Division in the System Integration Department.

Q. What will your testimony cover?

A. My testimony will cover Hawaiian Electric's continuing need for the Campbell Industrial Park Generating Station and Transmission Additions Projects (the "CIP CT-1 Projects") and the nominal 100 megawatt simple-cycle combustion turbine generator and related equipment and auxiliary facilities ("CIP CT-1").

Q. Did you previously submit testimony in this proceeding?

A. Yes, I did. I previously submitted testimony in HECO T-4.

II. HAWAIIAN ELECTRIC'S NEED FOR THE CIP CT-1 PROJECTS

Q. When did the Commission approve the commitment of expenditures for CIP CT-1 Projects?

A. The Commission approved the commitment of expenditures for the CIP CT-1 Projects in Decision and Order No. 23457 ("D&O 23457"), issued May 23, 2007, in Docket No. 05-0145.

Q. Were you a witness in Docket No. 05-0145?

A. Yes. In my role as Director of the Generation Planning Division (which was in the Power Supply Services Department), I presented direct testimony as HECO

T-1 (filed April 18, 2006) and rebuttal testimony as HECO RT-2 (filed September 28, 2006).

Q. What evidence did you present?

A. In my direct testimony, I covered the need for additional firm generating capacity, capacity planning considerations, and the type and size of firm generating capacity selected. My testimony demonstrated that HECO needed the generation provided by the CIP CT-1 Projects "today." However, because of the long lead times that it takes to permit and install new generation, HECO anticipates that the soonest the project can be placed into service is July 2009."

In my rebuttal testimony, I updated the need for additional firm generating capacity, and reiterated that, not only does Hawaiian Electric need an additional firm capacity generating facility for utility purposes to meet future customer demand for electricity, Hawaiian Electric needed the additional generating facility as soon as possible as it currently has a "reserve capacity shortfall".

The evidence that Hawaiian Electric presented is summarized in the Commission's D&O 23457 approving the project on pages 17 to 24.

Q. What is a reserve capacity shortfall situation?

A. "Reserve capacity shortfall" is defined as the amount of additional firm generating capacity or equivalent reductions in load from load management and energy efficiency demand-side management ("DSM") programs installations needed to restore the generating system reliability above Hawaiian Electric's reliability guideline.

A reserve capacity shortfall situation is a situation where Hawaiian Electric does not have as much firm generation as is called for by our capacity planning considerations to meet the highest demand of our customers. If

Hawaiian Electric is in a reserve capacity shortfall situation and a unit must be taken out of service for emergency maintenance, or a unit is unexpectedly forced out of service, or actual demand exceeds the forecasted demand, then Hawaiian Electric may not be able to provide electric service to some of Hawaiian Electric's customers.

Q. When did Hawaiian Electric report the reserve capacity shortfall situation?

A. In our annual Adequacy of Supply ("AOS") report filed March 31, 2004, we updated the need date for our next generating unit based on a new, higher long-term sales and peak forecast.

The report stated that, with the new forecast, projected generating system reliability would fall below the reliability guideline applied to determine the need date for new firm capacity beginning in 2006, if no new central-station generating capacity is added prior to that year, and even if forecasted peak reduction benefits from continuation of existing energy efficiency DSM programs are acquired, proposed peak reduction benefits from the two proposed load management programs are acquired, and proposed utility combined heat and power ("CHP") program impacts occur as forecast. Given the estimated lead time to install our next planned unit, which was a simple cycle combustion turbine ("CT") at our Barbers Point Tank Farm in Campbell Industrial Park, we noted that it was not possible to have the next HECO unit installed and operating by 2006, and we were exploring options to mitigate the effects of the higher forecast on generating system reliability.

Q. What steps did Hawaiian Electric take to keep regulators updated on the reserve capacity shortfall situation?

A. Hawaiian Electric updated the reserve capacity shortfall situation in a number of filings including:

1. Hawaiian Electric's 2005 Adequacy of Supply report ("2005 AOS"), filed with the Commission on March 10, 2005, indicated that Hawaiian Electric's reserve capacity shortfall was projected to be approximately 50 to 70 MW in the 2006 to 2009 period, assuming that Hawaiian Electric is able to implement its proposed DSM programs as planned and obtains approval for and successfully implements a utility CHP program and/or individual CHP agreements, and begins installing CHP systems in mid-2006.
2. In the Hawaiian Electric 2005 test year rate case in Docket No. 04-0113, Hawaiian Electric responded to numerous Consumer Advocate information requests regarding the 2005 AOS and the need for additional capacity. In particular, Hawaiian Electric's response to CA-IR-444 summarized the conclusions of the 2004 and 2005 AOS reports highlighting Hawaiian Electric's firm capacity needs. Hawaiian Electric's response to CA-IR-445 summarized the scenarios evaluated to assess generating system reliability. Hawaiian Electric's response to CA-IR-446, page 8, summarized Hawaiian Electric's effort to install a nominal 100 MW simple cycle combustion turbine by 2009. Hawaiian Electric response to CA-IR-557 provided a chronology of its generating system reliability assessments.
3. Hawaiian Electric's third IRP ("IRP-3"), filed with the Commission on October 28, 2005 in Docket No. 03-0253, indicated that a simple cycle combustion turbine is targeted for installation in 2009, which is the earliest it can be installed.
4. Hawaiian Electric's letter, dated December 5, 2005, to the

Commission in the Energy Efficiency Docket (Docket No. 05-0069), indicated that "Hawaiian Electric continues to experience a reserve capacity shortfall." (See Exhibit C, page 3, to the December 2005 letter.)

5. In Hawaiian Electric's 2006 AOS report, filed on March 6, 2006, Hawaiian Electric indicated that "Approximately 170 MW of additional peak load reduction measures and/or generating capacity would be needed in 2006 in order to maintain generating system reliability at or above Hawaiian Electric's reliability guideline ... The reserve capacity shortfall is projected to be approximately 170 to 200 MW in the 2007 to 2009 period (without including the addition of the Campbell Industrial Park combustion turbine in 2009)."

6. In my written rebuttal testimony (HECO RT-2, pages 2 to 11) filed September 28, 2006, in Docket No. 05-0145.

7. In Hawaiian Electric's 2007 AOS report, filed on February 27, 2007, Hawaiian Electric indicated that "HECO's latest estimates for this 2007 AOS place the reserve capacity shortfall for the Reference Scenario at approximately 70 MW in the 2007-2008 period…. HECO also estimates that the reserve capacity shortfall would be in the range of 20 to 40 MW for years 2009-2012 , if the nominal 110 MW Campbell Industrial Park combustion turbine is installed in mid-2009".

8. In Hawaiian Electric's IRP-3 2007 Evaluation Report filed May 31, 2007 in Docket No. 03-0253.

9. In Hawaiian Electric's 2008 AOS report, filed on January 30, 2008,

Hawaiian Electric indicated that "After the planned mid-2009 addition of the CIP generating unit, and in recognition of the uncertainty underlying key forecasts, HECO anticipates the potential for continued reserve capacity shortfalls in the range of 20 MW to 80 MW in 2010, up to a range of 70 MW to 130 MW in 2014."

10. In Hawaiian Electric's 2009 AOS report, filed on February 27, 2009, Hawaiian Electric indicated that " The scenario analysis indicates that in 2010, HECO may experience anywhere from a 10 MW reserve capacity shortfall under the higher load scenario to a 50 MW reserve capacity surplus in the reference scenario. By 2014, HECO may experience anywhere from a 40 MW reserve capacity shortfall under the higher load scenario to a 20 MW reserve capacity surplus in the reference scenario."

11. In Exhibit 2 of Hawaiian Electric's CIP CT-1 cost report submitted to the Commission on May 6, 2009, Hawaiian Electric reviewed the reserve capacity analysis without CIP CT-1. As discussed in more detail below, this analysis showed that CIP CT-1 is still needed.

Q. Is it possible to precisely forecast when generation will have to be added to avoid a reserve margin shortfall?

A. No. As is indicated in the AOS reports, the calculation of reserve capacity shortfall is dependent on uncertain assumptions, such as the load forecast. To evaluate the ramifications of differing assumptions, we perform analyses based on scenarios that illustrate the relationship between certain key inputs, or combination of inputs, and the resulting reserve capacity shortfall.

Q. What is the risk associated with a reserve capacity shortfall situation?

A. As we have reported, until sufficient generating capacity can be added to the system, we experience a higher risk of generation-related customer outages. The actual risk of generation-related customer outages depends, among other factors, on (1) the actual peaks experienced by the system, (2) success in implementing the energy efficiency and load management programs, and customer participation in these programs, (3) our ability and the ability of our IPP partners to minimize unplanned or extended outages of existing generating units, and (4) the extent to which mitigation measures can be implemented.

Q. Did Hawaiian Electric take steps to implement mitigation measures?

A. Yes. As is also indicated in the AOS reports, we have taken a number of steps to mitigate the effects of reserve capacity shortfalls, such as (1) installing temporary, limited run-hour distributed generators at substations or other sites, (2) implementing additional load management and other demand reduction measures, (3) pursuing efforts to improve the availability of generating units, (4) negotiating and obtaining approval of the Kalaeloa amendments adding 28MW of firm capacity in 2005, and (5) permitting and designing the CIP CT-1 so that it could be installed in 2009.

Q. Has Hawaiian Electric actually experienced a capacity shortfall, where service to customers needed to be interrupted due to a shortage of generating capacity?

A. Yes. On June 1, 2006, Hawaiian Electric experienced an actual capacity shortfall that resulted in the interruption of service to approximately 37,000 customers. Prior to the load shedding incident, four Hawaiian Electric generating units (Waiau 3, Waiau 4, Waiau 5 and Kahe 2) were on scheduled maintenance. On the day before the incident, Kalaeloa CT2 needed to be taken out of service for an emergency shutdown to repair a tube leak in its heat recovery steam generator. At around noon on June 1, Kalaeloa unit 1 tripped due to a problem with its voltage regulator. Later that afternoon, two additional Hawaiian Electric units (Waiau 9 and 10) tripped out of service as their voltage regulators exceeded their operating limits. Load needed to be shed from the system to restore the balance between supply (generation) and demand (load).

III. CONTINUED NEED FOR CIP CT-1

Q. What has been Hawaiian Electric's recorded peak demand since 2004 when Hawaiian Electric filed its AOS Report on its reserve capacity shortfall situation?

A. The following table illustrates Hawaiian Electric's historical system peaks from 2004-2008. The figures reflect an upward (stand-by) adjustment to account for the potential need to serve certain large customer loads (Chevron, Tesoro and Pearl Harbor) that are frequently served by their own internal generation.

Net System Peak (MW) (with Future DSM, but without Load Management & Rider I)		
Year	Actual	Actual Adj for Standby
2004	1,281	1,302
2005	1,230	1,250
2006	1,266	1,290
2007	1,216	1,241
2008	1,186	1,191

Q. Did Hawaiian Electric reassess its reserve capacity situation subsequent to the filing its 2009 AOS report on February 27, 2009?

A. Yes, it did. Hawaiian Electric submitted its reassessment in Exhibit 2 in its CIP CT-1 cost report submitted to the Commission on May 6, 2009 in Docket No. 05-0145.

Q. What did Hawaiian Electric indicate in that Exhibit 2 with respect to its reserve capacity situation?

A. Exhibit 2 of the CIP CT-1 cost report, showed the reserve capacity shortfall results of Table 8 from page 17 of the 2009 AOS report submitted to the Commission on February 27, 2009, based on Hawaiian Electric's September 2008 Sales and Peak forecast:

Table 8: Reserve Capacity Shortfall for Reference and Planning Scenarios (MW) With CIP CT-1

		Alternate Scenarios		
Year	Reference Scenario	Two-Month 90 MW Outage	Higher Load (Add 60 MW)	10 yrs/day reliability scenario
2009	-30	-60	-90	-70
2010	50	30	-10	20
2011	30	10	-30	0
2012	10	0	-50	-20
2013	30	0	-30	-10
2014	20	0	-40	-10

(Note: Negative values indicate a shortfall; a positive value indicate a surplus)

Exhibit 2 also provided supplemental analysis of the reserve capacity shortfall if CIP CT-1 is not installed:

Table 8A: Reserve Capacity Shortfall for Reference and Planning Scenarios (MW) Without CIP CT-1

		Alternate Scenarios		
Year	Reference Scenario	Two-Month 90 MW Outage	Higher Load (Add 60 MW)	10 yrs/day reliability scenario
2009	-60	-80	-120	-90
2010	-40	-70	-100	-80
2011	-60	-90	-120	-100
2012	-80	-90	-140	-110
2013	-70	-100	-130	-100

2014	-70	-90	-130	-110

As shown in Table 8, in 2009, Hawaiian Electric will experience a reserve capacity shortfall in all scenarios examined. For example, the Reference Scenario shows a -30 MW shortfall in 2009. This is a result of the reserve capacity shortfalls that occur early in 2009 until CIP CT-1 is installed. After CIP CT-1 is assumed to be installed in August 2009, no additional shortfalls occur in future years for the Reference Scenario. The reserve capacity shortfall amounts will be larger without the additional 113 MW of firm capacity to be provided by CIP CT-1. As expected, Table 8A shows that the projected reserve capacity shortfalls increase significantly in the absence of CIP CT-1.

Q. Does Hawaiian Electric have a more current forecast peak demand than that used in the Exhibit 2 update?

A. Yes, it does. Hawaiian Electric has developed a May 2009 sales and peak forecast. The following table provides a comparison of the September 2008 sales and peak forecast used in the 2009 AOS report and Hawaiian Electric's May 2009 forecast. The large difference in the peak forecasts illustrates the uncertainty the future holds, and that changes to the load forecast can be quick and pronounced.

Net System Peak (MW)
(with Future DSM, but without Load Management & Rider I)

Year	2009 AOS Sept 2008 S&P	May 2009 S&P
2009	1,246	1,183
2010	1,243	1,165
2011	1,252	1,176
2012	1,264	1,208
2013	1,296	1,219
2014	1,319	1,243

Q. Given this lower forecast, is CIP CT-1 still needed?

A. Yes. CIP CT-1 is still needed to maintain Hawaiian Electric's generating system reliability above its generating system reliability guideline. The analysis of the May 2009 sales and peak forecast if CIP CT-1 is not included produced the results shown below:

Reserve Capacity Shortfall for Reference and Planning Scenarios (MW)

Without CIP CT-1, With May 2009 Sales and Peak Forecast

Year	Reference Scenario	Higher Load (Add 60 MW)
2009	-10	-70
2010	20	-40
2011	10	-50
2012	-30	-90
2013	-10	-70
2014	-10	-70

As shown in the above table, Hawaiian Electric may experience reserve capacity shortfalls under the May 2009 sales and peak forecast. However, the reserve capacity shortfall analysis is very sensitive to the load forecast. In the case of the Higher Load Scenario, a nominal 60 MW increase in the forecasted load resulted in a 60 MW change to the results. Expectations regarding future loads can change quickly, and Hawaiian Electric may not be able to respond quickly to increases in demand. This illustrates the importance of using scenario analysis as a planning tool. The reserve capacity shortfalls may be avoided with the additional 113 MW of firm capacity to be provided by CIP CT-1. Supplemental analysis to quantify the amount of the reserve capacity shortfall based on the May 2009 forecast with CIP CT-1 included was performed. The results are as follows:

Reserve Capacity Shortfall for Reference and Higher Load Scenario With CIP

CIP CT-1 (MW)

Year	Reference Scenario	Higher Load (Add 60 MW)
2009	10	-50
2010	120	60
2011	100	40
2012	60	0
2013	90	30
2014	90	30

As expected, the projected reserve capacity shortfalls are eliminated with the installation of CIP CT-1 for 2009, as well as for future years.

IV. SUMMARY

Q. Please summarize your testimony.

A. The consequence of having insufficient reserve capacity on the system is that there is a greater likelihood that Hawaiian Electric's customers may experience service interruptions due to the unexpected outage of one or more generating units, i.e., there is a higher probability that some lights could go out. It is important to note that while Hawaiian Electric has the ability to delay the execution of a resource plan when circumstances -- such as an economic slump resulting in reduced load growth -- lead to a reduction in urgency, it has very limited ability to accelerate resource plans if unanticipated changes in key drivers demand that firm capacity is needed sooner than anticipated. Furthermore, the commitment to move to renewable energy in compliance with state policy, the growing uncertainty of what the future holds, coupled with the increasing time required by engineering, technical, operational, and environmental processes to add firm generation capacity – all these factors drive the very need to take affirmative action to pursue new firm capacity additions if Hawaiian Electric is to be in a position to meet the challenges of integrating intermittent renewable resources on its system and taking traditional fossil-fueled units off the system.

Q. Does this conclude your testimony?

A. Yes, it does.

Witness HECO ST-4

has no supplemental exhibits.

HECO ST-7
DOCKET NO. 2008-0083

SUPPLEMENTAL TESTIMONY OF
DAN V. GIOVANNI

MANAGER
POWER SUPPLY O&M DEPARTMENT
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Employee Count; Operational Value of the CIP CT-1; Significant Expense Increases of Production O&M; Commodity Prices – Other Production Maintenance

SUMMARY OF OTHER PRODUCTION O&M EXPENSE

Q. Please state your name and business address.

A. My name is Dan V. Giovanni. My business address is 475 Kamehameha Highway, Pearl City, Hawaii.

Q. By whom are you employed and in what capacity?

A. I am the Manager of the Power Supply Operations and Maintenance ("PSO&M") Department at Hawaiian Electric Company, Inc. ("Hawaiian Electric" or "Company"). My educational background and work experience are listed in HECO-700.

Q. Have you previously testified in these proceedings?

A. Yes, I submitted written direct testimony, exhibits and supporting workpapers as HECO T-7.

Q. What is the nature and scope of your current supplemental testimony?

A. My supplemental testimony supports the Company's response to concerns raised by the Commission in Sections III.(a), III(c), III(j), and II.2.(d) of its Interim Decision and Order ("Interim D&O"), issued on July 2, 2009 in this docket. Specifically, my testimony will address the employee count of PSO&M, operational value of the Campbell Industrial Park Combustion Turbine Unit 1 ("CIP CT-1"), significant expense increases of Production Operations and Maintenance ("O&M"), and Other Production Maintenance in relation to commodity prices.

EMPLOYEE COUNT

Q. Is the increase in the number of employees in the Power Supply Process Area between 2007 and 2009 reasonable?

A. Yes. In its Interim Decision and Order, the Commission required additional information from Hawaiian Electric to determine whether the increase in the number of employees between 2007 and 2009 is reasonable. Comparing the 2007 and 2009 staffing levels within the Power Supply Process Area is not easily accomplished because, as discussed in HECO ST-15 and HECO ST-1 and the Company's responses to CA-IR-456 and CA-IR-458, during this period there were several re-organizations. Therefore, to facilitate the explanation my testimony presents two tables. The first table, HECO-S-1510, compares the 2007 rate case settlement test year average and the 2009 rate case update test year average in the Power Supply Process Area as if March 2009 reorganization had never taken place. The second table, HECO-S-1511, compares the 2007 settlement test year average and the 2009 rate case update test year average in the Power Supply Process Area as if the re-organizations, including the one effective March 2, 2009, were in effect in both 2007 and 2009. Providing these two illustrative tables facilitates a consistent, "apples-to-apples" comparison of both the historical and current company organizations. In both cases, the respective overall employee headcounts for the 2007 rate case settlement and 2009 rate case update did not change, as demonstrated in HECO ST-15.

PRODUCTION STAFF LEVEL UNDER FORMER ORGANIZATION

Q. Please explain the growth in the Power Supply Process Area between 2007 and 2009 as if there were no intervening re-organizations.

A. Assuming there were no intervening re-organizations, as shown in HECO-S-1510 and summarized in the table below, the 2009 rate case update test year average for the Power Supply Process Area is 498, which is 40 positions more than the 2007 settlement test year average of 458.

Power Supply Process Area – Additional Positions
(as if there were no intervening re-organizations)

Department	2007 Test Year Average	Updated 2009 Test Year Average	Difference
PSO&M	353	375	22
PS Engineering	46	53	7
Environmental	24	25	1
PS Services	11	17	6
System Planning	22	25	3
VP – PS Office	2	3	1
PS Process Area	458	498	40

Q. Please explain the differences shown above the Vice President's Office in the Power Supply Process Area.

A. The one additional position in the Vice President-Power Supply Office is the Manager of Renewable Energy Integration. This position was created to assist with technical issues associated with the integration of variable generation (e.g., wind and PV sources of energy) into the HECO grid on Oahu.

Q. Please explain the differences of 22, seven, one, six, and three positions for the PSO&M, PS Engineering, Environmental, Power Supply Services, and System Planning Departments, respectively.

A. These differences are explained for each of these five departments below.

Power Supply Operations and Management (PSO&M) Department

Q: For the PSO&M Department, what is the difference in staffing level between the 2007 rate case settlement test year average and the 2009 rate case update test year average?

A. As shown in the table above in more detail in HECO-S-1510, there was a net increase of 22 positions in the PSO&M Department from the 2007 Test Year Average to the Updated 2009 Test Year Average. The net increase of 22 positions consisted of the elimination of 11 positions and the adding of 33 new and reassigned positions. Of the 33 new and reassigned positions, 15 positions were for the new, permanent staff at CIP CT-1.

Q. Please describe the positions added to the PSO&M Department from the 2007 Test Year Average to the Updated 2009 Test Year Average.

A. The PSO&M Department organization and descriptions of positions in the PSO&M Department are discussed in detail in HECO T-7, pages 47 to 65.

Q. What is the status of efforts to fill the vacancies in the PSO&M Department?

A. As shown in HECO-S-1510, as of June 9, 2009, 359 of the 375 positions in the 2009 rate case update test year average have been filled. As of that date there were 16 vacancies. HECO has been making steady progress to fill the vacant positions, but as discussed in HECO T-7, pages 58 to 59, and the response to CA-IR-77, it continues to be difficult to fill journeyman trades-and-craft positions in the PSO&M Maintenance Department. In addition, there continues to be a few vacancies among the merit positions, including two Technical Trainers, supervisors in the Operating and Maintenance Divisions, and clerical position at

CIP CT-1. With the exception of the Technical Trainer positions the vacancies have been created by normal turnovoer (i.e., promotions, transfers, and retirements) and should not be difficult to fill on a timely basis. The vacant Technical Trainer positions have been more problematic to fill, and accordingly outside contractors are being utilized to address training needs.

Q. What have been the consequences of vacancies for the established positions in the Operating and Maintenance Divisions?

A. As a result of having approximately 20 vacancies (some months more and some months less) HECO has experienced the following consequences:

- The utilization of contractors has increased, that is Supplemental Labor, to be greater than that budgeted to perform maintenance work that would otherwise be performed by Maintenance trades-and-crafts personnel.
- The level of overtime worked by Maintenance Division trades-and-crafts personnel has increased.
- The level of overtime worked by qualified operators in the Operating Division has increased to assure that full complements of qualified operators are on duty 24 X 7 at all of HECO generating units.
- The backlog of lower priority maintenance work has increased.

<u>Power Supply Engineering Department</u>

Q: For the Power Supply Engineering Department, what is the difference in staffing level between the 2007 rate case settlement test year average and the 2009 rate case update test year average?

A: For the Power Supply Engineering Department there was an increase of seven positions between the 2007 rate case settlement test year average and the 2009 rate case update test year average, to a total of 53 positions.

Q: Explain the reasons for this increase of seven staff members.

A: Four of the seven new positions in the 2007 rate case settlement test year average versus the 2009 rate case update test year average occurred in the Power Plant Engineering Division of the Power Supply Engineering Department. These new positions were needed based on forecasted workload to support HECO's capital improvement program, the O&M program for HECO's existing generating units. and the Production Departments at HELCO and MECO.

Two of the seven new positions in the 2007 rate case settlement test year average versus the 2009 rate case update test year average occurred in the Technical Services Division (TSD) of the Power Supply Engineering Department. The additional staff engineer positions were required to support succession planning for critical senior technical positions in TSD that support the HECO Generation Asset Management Program.

The final one of the seven new positions in the 2007 rate case settlement test year average versus the 2009 rate case update test year average occurred in the Support Staff Division of the Power Supply Engineering Department. The additional support staff position was needed to provide timely clerical and filing support for the professional staff.

Q. Are there currently any vacancies in the Power Supply Engineering Department?

A. Yes, as shown in HECO-S-1510, as of June 30, 2009, there are two vacancies in the Power Supply Engineering Department. One vacancy is in the Power Plant Engineering Division and the other vacancy is in the Technical Services Division. Filling these engineering vacancies has been problematic for several reasons including the limited local labor pool for engineers in general and even more so for power plant engineers. In addition, the specific skill sets required for these two positions are specialized skills within power plant engineering.

Q. What have been the consequences of vacancies for the established positions in the Power Supply Engineering Department?

A. The consequences of these vacancies have been increased workload for other department personnel, increased utilization of outside consultants and some deferral of lower priority work.

Environmental Staffing Testimony

Q: For the Environmental Department, what is the difference in staffing level between the 2007 rate case settlement test year average and the 2009 rate case update test year average?

A: For the Environmental Department there was an increase of one position between the 2007 rate case settlement test year average and the 2009 rate case update test year average, to a total of 25 positions.

Q: Explain the reasons for this increase of one staff member.

A: The increase of one position between the 2007 rate case settlement test year average and the 2009 rate case update test year average is the addition of a Analytical Chemist position. This position was added in 2008 and filled in

December 2008 to support the additional work load that has increased over the years, including the addition of CIP CT-1 and additional analysis associated with the implementation of biofuels. This is the first increase in staffing since the Environmental Chemistry Lab's inception in the 1970's.

Q. Are there currently any vacancies in the Environmental Department?

A. No, as shown in HECO-S-1510, as of June 30, 2009, all of the positions in the Environmental Department are filled.

Power Supply Services Department

Q: For the Power Supply Services Department, what is the difference in staffing level between the 2007 rate case settlement test year average and the 2009 rate case update test year average?

A: For the Power Supply Services Department, assuming no intervening re-organizations, there was an increase of six positions between the 2007 rate case settlement test year average and the 2009 rate case update test year average, to a total of 17 positions. The six additional positions are:

- Director, Renewable Energy Power Purchase
- Contract Negotiator, Renewable Energy Power Purchase
- Director Fuels Infrastructure,
- Staff Engineer (2), Fuels Infrastructure,
- Contract Administrator, Fuels Resource

Q. Why was each of these new positions required?

A. The Power Supply Services Department has created a new division, Renewable Energy Power Purchase, to manage the increasing number of renewable energy power purchase negotiations. This workload increase has been a direct result of the increase in recent years in the cost of electric energy generated by fossil fuels and the subsequent changes in state and corporate policies taken to mitigate this impact through new renewable energy power purchase contracts. In addition, the HCEI Agreement has formally incorporated accelerated deadlines and project milestones for many of the project proposals by these independent power producers ("IPP"). The focus on integrating up to 400 MW of neighbor island wind energy into the Oahu grid and the desire expressed in the HCEI Agreement to renegotiate existing IPP contracts that are based on the avoided cost of fossil fuel will soon add additional demands to the existing Power Purchase Division.

While the changes in policy and cost of fossil fuel in the last few years have created the need to add additional staffing and reorganize, the HCEI Agreement makes the acquisition of these resources imperative.

Fuels Infrastructure Division is supervised by the Director of Fuels Infrastructure and consists of 2 staff engineers. The reorganization creates the focused team necessary to manage existing and new fuel infrastructure and systems, pipeline integrity compliance management, new supply relationships and the increased operational complexity associated with the requirements of new biofuels.

A contract administrator was added to the Fuels Resources Division to manage fuel supply and logistics operations. The existing staff level was unable to provide effective planning, efficient asset/service utilization, and auditable and

SOX/complaint contract administration for the procurement of raw materials and services.

Q. Are there currently any vacancies in the Power Supply Services Department?

A. Yes, the Director Renewable Energy Power Purchase, as shown in HECO-S-1510, as of June 30, 2009.

Q. What have been the consequences of vacancies for the established positions in the Power Supply Services Department?

A. Renewable Energy Power Purchase effort has been prioritized in order to achieve the Hawaii Clean Energy goals. This has resulted in some priority work delays. This has been mitigated through the retention of outside attorney services. However, the performance of these priority tasks will continue to be sub-optimized until full staffing is achieved.

Fuels Infrastructure Division activities were supported thru limited use of outside contractors. Reprioritization of work, delays in pipeline compliance, infrastructure maintenance and repairs are consequences without the Fuels Infrastructure division.

The Fuels Resource contract administration staff increasingly were unable to provide effective planning, efficient asset/service utilization, and auditable and sox/complaint contract administration for the procurement of raw materials and services.

System Planning Department

Q: For the System Planning Department, what is the difference in staffing level between the 2007 rate case settlement test year average and the 2009 rate case update test year average?

A: For the System Planning Department, assuming no intervening re-organizations, there was an increase of four positions between the 2007 rate case settlement test year average and the 2009 rate case update test year average, to a total of 25 positions. The four additional positions are a result of the addition of the Renewable Energy Planning Division in the System Planning Department as follows: one Director, Renewable Energy Planning; one Senior Renewable Energy Engineer; and two Renewable Energy Engineers. The position descriptions for each of these four positions are found in Attachment 10 to HECO T-7 Rate Case Update.

Q. Why was each of these new positions required?

A. As explained in the HECO T-7 Rate Case Update, the Renewable Energy Planning Division establishes dedicated technical capabilities and focused leadership to direct a wide range of in-house resources and leverage external resources as needed to analyze the impact of new renewable energy projects on the utility systems and achieve their timely and cost-effective integration. The division's primary responsibility will be to lead the development of appropriate strategies, methods, plans, and policies to achieve successful integration of renewable energy projects for HECO, HELCO and MECO. Their work to date is more fully described in HECO ST-15C.

Q. Are there currently any vacancies in the System Planning Department?

A. No, all positions in the System Planning Department are currently filled.

PRODUCTION STAFF LEVEL UNDER NEW ORGANIZATION

Q. Have there been intervening re-organizations 2007 and 2009 that affected the Power Supply Process Area?

A. Yes, there were two re-organizations between 2007 and 2009 that affected the Power Supply Process Area. The first re-organization created new divisions in the Power Supply Services and System Planning Departments and was described in the Update to the 2009 Rate Case (HECO T-7 Rate Case Update, pages 26-32). The second re-organization affected the Power Supply Process Area in three ways: (1) Personnel from the Power Purchases Divisions of the Power Supply Services Department were assigned to the new Resource Acquisition Department of the Clean Energy Process Area, (2) The System Planning Department (in its entirety) was reassigned to the Clean Energy Process Area; and (3) The Fuels Department was created in the Power Supply Process Area comprised of the Fuels Resources and Fuels Infrastructure Divisions. Greater discussion on the new organizations that transferred from the Power Supply Process Area is presented in HECO ST-15C (Leon Roose) and HECO ST-15D (Scott Seu). The Fuels Department is discussed below.

Q. Please explain the growth in the Power Supply Process Area between 2007 and 2009 as if the intervening re-organizations occurred in 2007.

A. Assuming the intervening re-organizations occurred in 2007, as shown in HECO-1511 and summarized in the table below, the 2009 rate case update test year average for the Power Supply Process Area is 464, which is 31 positions more than the 2007 settlement test year average of 433.

Power Supply Process Area – Additional Positions
(as if intervening re-organizations were in effect in 2007)

Department	2007 Test Year Average	Updated 2009 Test Year Average	Difference
PSO&M	353	375	22
PS Engineering	46	53	7
Environmental	24	25	1
Fuels (formerly) PS Services	8	9	1
VP – PS Office	2	2	0
PS Process Area	433	464	31

Q. Please explain the differences of 22, seven, and one positions for the PSO&M, PS Engineering, and Environmental Departments, respectively.

A. The differences for PSO&M, PS Engineering and Environmental Departments are identical to the case presented and discussed above.

Q. Please explain the difference of one position for the Fuels Department.

A. The Fuels Department (formerly the Power Supply Services Department until March 2, 2009) staffing level increased from eight in the 2007 rate case settlement test year average to nine in the 2009 rate case updated test year average as described in HECO T-7, page 72, lines 17 to 23. Organizational changes are also described in the response to CA-IR 456, Attachment 1, and the organizational structure is shown in the response to CA-IR-458, Attachment 1.

Q. Why was the Fuels Department (former Power Supply Services Department) employee count increase of one required?

A. The Fuels Department, Fuels Resources Division is unique in HECO, MECO and HELCO in its function and for the kind and degree of knowledge and experience required of its personnel. The successful management of fuel supply and logistics operations, the efficient administration of the complex commercial processes and the effective supervision of distribution facility and transportation services required for the procurement and control over the Companies' basic raw materials is necessary for the profitable and safe generation of electric power. The 2007 staff level were increasingly unable to provide effective planning, efficient asset/service utilization, and auditable and SOX/complaint contract administration for the procurement of raw materials and services. The large financial significance and high degree of operational risk combined with the inherently confidential nature of fuel procurement arrangements and performance of contract administration justifies a much larger degree of internal control and accountability than can be obtained through a reliance upon an outside third-party contractor or temporary worker.

Q. Are there currently any vacancies in the Fuels Department?

A. No, currently all positions are filled.

OPERATIONAL VALUE OF CIP CT-1

Q. How does CIP CT-1 add value to the Hawaiian Electric generation system and the electric grid on Oahu?

A. CIP CT-1 provides significant value in three general ways: (1) allows Hawaiian Electric to more effectively integrate increasing levels of renewable variable generation resources (such as wind and solar electric energy) into the Oahu grid; (2) eliminates the need to commit up to two other cycling and/or peaking units to provide 30 to 50 MW of generation and 60 to 80 MW of spinning reserve (and achieved firing biodiesel, and not fossil fuel, thus reducing the "carbon footprint" of the generating system); and (3) delivers on Hawaiian Electric's fundamental "obligation to serve" by maintaining an appropriate and responsible level of firm generating capacity on Oahu.

Q. Why are Hawaiian Electric generating units needed to support renewable variable generation such as wind or photovoltaic ("PV") generation on the Hawaiian Electric system?

A. Power systems require that the generation resources on the system collectively provide several characteristics that the system fundamentally needs for reliable operation. These characteristics include adequate firm generating capacity, voltage regulation, dispatchable generation, frequency regulation, and sufficient rotational inertia to maintain system stability. Baseload, cycling, and peaking generating units are commonly referred to as "firm" power, and their power output can be dispatched as needed. Variable generation resources like wind and PV are not firm, can not be dispatched, and are unable to provide prescribed amounts of power upon command or at scheduled times. Firm power sources, like CIP CT-1, have important operational characteristics that facilitate and support the integration of variable generation resources. Safe and reliable operation of the system is not possible without these firm power sources. These important operational characteristics are further discussed below.

<u>Capacity</u>. Hawaiian Electric's obligation to serve means it needs to have

enough generating capacity on the system to reliably serve the expected system loads. To do this Hawaiian Electric needs generation that it can count on when needed. CIP CT-1 would provide up to 110 megawatts ("MW") of capacity on demand, and would be dispatched as needed to serve the system load.

Dispatchability. Hawaiian Electric's firm power generating units are needed to maintain a balance between the system generation and the system load demand. For example, as the load grows during the day, dispatchable generators that can be reliably set to specified output levels are needed to maintain this balance. The power output of variable generation resources like wind and PV are not dispatchable and their power output at any time is a function of the natural conditions of the environment. Accordingly, to maintain the balance between system generation and load demand, the power output of Hawaiian Electric's firm power generating units must be continuously dispatched to counter balance the output (either up or down) of variable generators.

Frequency Regulation. The electric system needs to carry adequate amounts of regulating reserve and spinning reserve. Regulating reserve is the amount of operating reserve measured in megawatts (both up and down) that is automatically controlled by Hawaiian Electric's automated Energy Management System. The purpose of regulating reserve is to maintain a "cushion" for responding to changes in load demand or power output from generation sources connected to the grid. In this way, total system demand and supply are kept in balance and system frequency is maintained at 60 Hertz ("Hz"). Firm power generating units have the capability to increase or decrease their power output quickly and in a controlled manner in response to changes in system frequency. Spinning reserve is the amount of operating reserve in megawatts that may be dispatched to cover the sudden loss of a generating unit connected to the grid.

The loss of a generating unit results in a decay in system frequency, and the spinning reserve on the other units connected to the grid is utilized to restore system frequency to 60 Hz. Hawaiian Electric's spinning reserve criterion provides for the loss of the largest generating unit on the grid. Only firm power generating units, like CIP CT-1, have the capability to provide spinning reserve. Regulating reserve is a subset of spinning reserve.

Voltage Regulation. Similar to the dispatch of megawatts to maintain system frequency, real and reactive power is also dispatched from the firm power generating units to control system voltages within proper limits throughout the grid.

Rotational inertia. System stability is the ability of an electrical system to continue to operate and remain stable during a period of disturbances, such as a sudden loss of load resulting from a power interruption, or the initiation of system protection measures resulting from a system fault condition. Characteristic features of firm power generating units, like CIP CT-1, include rotational inertia to provide for system stability. The combined rotational inertia of firm power generation connected to the system needs to be large enough to enable the electric system to effectively "ride through" the first few seconds of major system disturbances. When a major disturbance occurs, like the sudden loss of a large generating unit, the electric grid draws the power it needs to stabilize the grid from the rotational inertia of the steam turbines, combustion turbines, and electric generators. Within seconds power extracted from the rotational inertia of firm generating units stabilizes the frequency of the grid at a value near 60 Hz. Then, as described above, the spinning reserve in the firm power units is dispatched to restore the system to 60 Hz. Variable generation sources generally provide little or no rotational inertia to the system and when on-line, can displace generators that have this critical characteristic. Stability issues are extremely important on island electrical systems that are not interconnected with other utility grids and, thus, cannot receive assistance from another grid in the event of a destabilizing disturbance.

Q. How will Hawaiian Electric's firm power generating units be impacted by more variable generation on the Oahu grid.

A. The operation and maintenance of the Company's current generating units will be impacted in several ways as more variable generation sources become connected to the Hawaiian Electric grid. The impacts include the following:

- Hawaiian Electric's baseload, cycling, and peaking generating units will have to operate in a more dynamic mode (i.e., changing loads more often and at higher load ramp rates) to counter balance the more volatile and unpredictable power from the variable generation.
- As more energy is produced from variable generation, Capacity Factors ("CF") of Hawaiian Electric's baseload, cycling, and peaking units will decrease. However, since these units need to been on line for frequency regulation, voltage regulation, and spinning reserve, the decreases in CFs will mean that the Company's units will operate more hours at lower loads.
- Operation of the Company's generating units with more hours at lower loads will result in increased heat rates (i.e., more fuel consumed per unit of power produced).
- Variable generation sources typically do not provide ancillary services (e.g., voltage support, frequency control, etc.) for the grid. Hawaiian Electric may have to compromise economic dispatch of its firm power

generating units, and commit and dispatch generating units based on other factors in order to manage the grid. This would also negatively affect heat rate.

Q. How would CIP CT-1 allow Hawaiian Electric to more effectively integrate increasing levels of intermittent and variable renewable generation into the Oahu grid?

A. CIP CT-1 is a firm power generating unit with dynamic characteristics that exceed those of Hawaiian Electric's other existing firm power generating units. In particular, CIP CT-1 may be started and connected to the grid in minutes (compared to hours for the steam units), and it may dispatched at ramp rates (up and down) that are up to 10 times greater than those for the steam units. For example, CIP CT-1 has a ramp rate of 13.4 MW, while the Company's steam units have ramp rates that range from 1 to 4 MW. Similarly, the largest generating unit on the Company's system, the coal-fired generating unit at the AES facility, also has limited ramping capability. There will be times during off-peak periods when the cycling units are off-line and the ramping capability of CIP CT-1 will be needed as the on-line steam units will not be able to provide the needed ramping to counter balance the unpredictable power from variable generation. Ultimately, the addition of new firm generating units on Oahu grid that have flexible characteristics like CIP CT-1 will further support the integration of renewable variable generation on the Hawaiian Electric system.

Q. Will the addition of CIP CT-1, the new peaking unit, relieve the duty of the Hawaiian Electric baseload generating units?

A. As discussed in HECO T-7, pages 10-13, the addition of CIP CT-1 will not materially affect the commitment, dispatch, or duty of the Hawaiian Electric baseload generating units. CIP CT-1 will, however, provide valuable reserve capacity which will be utilized to help meet spinning reserve criteria, and will help prevent generation shortfall incidents (i.e., rolling blackouts) during certain system emergencies. CIP CT-1 will also provide more flexibility in scheduling maintenance outages of the other generating units, including the baseload units, and this will result in fewer megawatt-hours ("MWh") than would otherwise be lost due to extended operation of derated baseload units that require an outage for corrective maintenance. Moreover, the rotational inertia of CIP CT-1 will provide for increased stability of the grid as more variable generation sources are added in the future.

Q. How would CIP CT-1 reduce the "carbon footprint" of the Hawaiian Electric generating system.

A. CIP CT-1 would help reduce the "carbon footprint" of the Company's generating system because it would operate on biofuels and not fossil fuels. Burning biodiesel will reduce greenhouse gas emissions. CIP CT-1 will be utilized most often to provide spinning reserve for the Oahu grid, and thus, would displace the generation otherwise provided by the Company's fossil fuel-fired cycling and peaking units. CIP CT-1 would be dispatched at 30 to 50 MW and provide up to 80 MW of spinning reserve. If not for CIP CT-1, Hawaiian Electric would have to dispatch two or three of its cycling steam units (Waiau 3, 4, 5 and 6, and Honolulu 8 and 9), or both of its peaking units (i.e., Waiau 9 and 10) to achieve similar levels of spinning reserve.

Q. How will CIP CT-1 contribute to the Company maintaining an appropriate and responsible level of firm generating capacity on Oahu?

A. CIP CT-1 is needed to give Hawaiian Electric the opportunity to fulfill its obligation to serve – to provide reliable electric power to its customers when they demand it. Hawaiian Electric has analyzed system reliability results under a range of possible energy futures, including two sensitivity scenarios based on a recent (and lower) September 2008 Short Term Sales & Peak forecast. Hawaiian Electric projects that in the years 2011, 2012, 2013, and 2014, there could be a reserve capacity of 40 MW, 10 MW, 20 MW and 20 MW, respectively (as shown in the reference scenario of the 2009 Adequacy Of Supply Report filed February 27, 2009) with the benefit of the 110 MW of capacity from CIP CT-1. Under some scenarios there is also the potential for a reserve capacity shortfall of up to 50 MW (as shown in the 2009 AOS (higher load) scenario) even with CIP CT-1 on line. The ranges are broad, and indicate the degree to which key planning assumptions such as the peak demand forecast can quickly and unexpectedly change over time.

Insufficient reserve capacity does not mean the lights will necessarily go out. If no generating units are unexpectedly lost from service, then service to all customers will be maintained. However, with insufficient reserve capacity, there is a greater likelihood that customers may experience service interruptions due to the unexpected outage of one or more generating units, i.e., there is a higher probability that outages could occur.

SIGNIFICANT INCREASES IN PRODUCTION O&M EXPENSE

Q. Please summarize Hawaiian Electric's Other Production O&M expense.

A. Other Production O&M expense is summarized in HECO-S-701, showing the labor and non-labor components for each year. Other Production O&M expense at Settlement totals $78,973,000. HECO-S-701 also reflects the total for Other Production O&M expense at direct testimony ($80,391,000), 2008 Recorded ($77,368,000), 2007 Recorded ($68,807,000), and 2007 Test Year Interim Decision and Order ($67,597,000).

Q. How do these expense amounts break down into Operations expense and Maintenance expense?

A. The break down into Operations expense and Maintenance expense is shown in HECO-S-702. These amounts are further broken down into labor and non-labor subtotals.

Q. Have the increases in certain expenses between the 2007 test year interim award to the 2009 test year been identified and explained previously?

A. Yes. The increases in expenses have been identified and explained in direct testimony, the rate case update, and responses to various information requests from the Consumer Advocate. In order to facilitate the Commission's review of the information already provided on the expense increases, HECO-S-703 has been created to list where the information can be found.

COMMODITIES PRICE INDEX

Q. What was the amount for materials in the Updated 2009 Test Year Estimate for Other Production Maintenance?

A. The amount for materials in the Updated 2009 Test Year Estimate for Other Production Maintenance is $8,871,000, as identified in CA-IR-309, Attachment 1, page 1.

Q. What were the budgeted and recorded amounts for materials in Other Production Maintenance from 2006 through 2009?

A. The budgeted and recorded amounts for materials in Other Production Maintenance from 2006 through 2009 are summarized below:

Materials – Other Production Maintenance ($000)

	2006	2007	2008	2009
Budget	9,158	7,738	10,352	8,871
Recorded	10,110	9,785	11,528	4,804 (through 5/30/09)
Difference	-952	-2,047	-1,176	4,067

The recorded amounts for materials have consistently been higher than the amount budget. The amount budged for 2009 is substantially below the amounts recorded in the previous three years. The amount recorded through the first five months of 2009 is $4,804,000, or 54% of the budget. If expenditures were to continue at this same rate for the remaining seven months, the recorded amount would be $11,530,000, exceed the estimated 2009 budget by $2,659,000, and reach 2008 recorded expenditure levels.

Q. Is there correlation between this trend of budgeted and recorded expenses as compared with the variation in commodity price indices?

A. No. The change in commodity prices does not correlate with the Production Maintenance expense for materials. In the current year as in recent years, Hawaiian Electric appears to have under-budgeted for Other Production Maintenance Materials. The trend to lower commodity prices in the fourth quarter of 2008 and first quarter of 2009 did not materialize in lower recorded expenses for maintenance materials.

Q. Can you provide an illustration of the trend in commodity price in recent months?

A. Yes. The price index for copper and brass mill shapes provided in Attachment HECO-S-704 is a trend for the period January 2007 to June 2009 for one of the more volatile commodities. From May to December in 2007, the index fell from 447.3 to 389.8. Then the price rose again to a peak of 446.6 in July 2008. By

February 2009, the index declined to 277.8, but then rose again reaching 357.7 in June 2009. Also displayed in HECO-S-704 is the Consumer Price Index (CPI-U). During that same period from January 2007 to June 2009, the Consumer Price Index (CPI-U) rose from 202.4 to 215.7.

Q. Does Hawaiian Electric utilize price indexes, like the one for copper and brass mill shapes, to calculate its test year Other Production Maintenance Materials estimate?

A. No. In response to CA-IR-393, the Company explained, "In general, HECO monitors the price trends that may affect the cost of performing its work. As stated in HECO T-7 direct testimony at page 102, HECO receives monthly updates from suppliers on market prices of commodities that affect materials price escalation. However, the price trends shown in HECO-745 were not explicitly used in estimating test year anticipated expense levels." The price indices served only as a general point of reference when estimating the Production Materials expense, i.e., changes in the indices were not used directly in computing estimated Production Materials expenses.

Q. Has Hawaiian Electric been able to find a correlation between the raw material price volatility and the price of fabricated materials that were purchased?

A. It's extremely difficult to observe the effects of commodity price volatility of this type in the prices for fabricated parts due to several reasons. As discussed in Exhibit 3, pages 17 to 20, of the Revised Schedules Resulting from Interim Decision and Order (Docket 2008-0083) filed with the Commission on July 8, 2009: "It is difficult and impractical to specifically identify the portion of this material cost that is for raw materials and subject to varying prices for commodities. It is also difficult to establish any specific cost relationship between this material cost and commodity pricing."

Materials used for Production Maintenance are overwhelmingly comprised of fabricated equipment, parts, and assemblies. The cost of raw materials used in the manufacturing of the fabricated materials is a small portion of the total material cost. The price of fabricated equipment, parts and assemblies tend to trend more along the Consumer Price Index curve than raw material commodity indices, such as the copper and brass mill shapes curve displayed in HECO-S-704.

Q. Please provide examples of fabricated materials commonly used for Production Maintenance.

A. Examples of fabricated materials commonly used for Production Maintenance include:

- Internal assemblies for large pumps. A key internal component of boiler feed pumps is the "volute," which is prone to wear. There are two or three of these pumps for each steam generating unit. Instead of replacing the whole pump when a volute wears out, it is common to have the volute refurbished at a mainland facility. The material price for a refurbished volute is approximately $170,000, and the price has steadily increased in recent years, including 2009. The raw materials used for the refurbishment of a volute is a trace fraction of the total cost.
- Air heater baskets. Each steam generator has one or two air heaters. The internal baskets are made of corrugated metal. The design of the basket is unique to the air heater and a "special order" must be placed several months in advance for the customized baskets. Air heater baskets are generally replaced every few years. The materials price for a set of air heater baskets is typically a few hundred thousand dollars. The raw materials used for the air heater baskets represent a small fraction of the cost.

- Boiler tubes. Steel tubes of varying chemical composition are used throughout the steam generator ("boiler"). Sections of a boiler (comprised of tubes) are typically changed when the tubes have eroded or corroded to an unacceptable degree. The tubes are typically fabricated by the boiler manufacturer with specific bends and terminations that facilitate the replacement process in the field. The raw materials used for boiler tubes can be a significant portion of the cost depending on their chemical composition.
- Valves. Valves that are repaired or refurbished typically have the internals replaced. These are fabricated parts that are machined to high precisions (i.e., thousandths of an inch) and pre-assembled. The raw materials used for refurbishment of valves represent a trace fraction of the total cost.
- Turbine Bearings and Seals. These components need to be machined to very high precision, and the work is typically done in qualified machine shops on the mainland. The machined seals and bearings are expensive, and the raw material cost of the fabricated product is a fraction of the cost.
- Fittings and Connectors. Tube fittings, conduit fittings, and electrical cable terminations are utilized in high volumes for maintenance. The components are pre-fabricated items and are purchased in different materials (e.g., stainless steel, brass, aluminum, copper). Even so, the cost of the material is typically a fraction of the cost of the fabricated item."

Q. How does Hawaiian Electric manage its maintenance work in view of the potentially volatile nature of commodity prices?

A. As discussed in the response to CA-IR-393, Hawaiian Electric monitors raw materials price indexes (similar to the information provided as HECO-745) because it illustrates the periodic volatility of raw material prices as well as the longer-term, general trend of material prices that affect the cost of performing work rising more quickly than the increase in the Consumer Price Index. When prices of fabricated materials are high, it results in work being performed at a cost that exceeds the budget (as it has in previous years) and lower priority discretionary work being deferred. Conversely, in periods when prices for fabricated materials are low it results in more work being performed, including lower priority infrastructure projects that are otherwise deferred.

Q. Did Hawaiian Electric provide an adjustment to Other Production Maintenance Expense in the Revised Schedules Resulting from Interim Decision and Order (Docket 2008-0083) filed with the Commission on July 8, 2009?

A. Yes. To offer an immediate reflection of any commodity pricing decrease that might have an impact on the fabricated materials costs, Hawaiian Electric proposed to reflect a $177,000 adjustment to Other Production Maintenance costs?

Q. Does Hawaiian Electric consider the adjustment of $177,000 to be required under the facts of this case?

A. No. Although Hawaiian Electric was willing to make a concession on this expense item in the interest of resolving the disputed issues in this proceeding, the reduction is not warranted because of the reasons discussed above, including: (a) Historical record demonstrating that Hawaiian Electric has consistently under forecast the cost for maintenance materials, including 2009; (b) Short term volatility of commodity prices including a significant increase in price indexes in recent months above the "lows" experienced in March 2009; (c) Absence of a correlation between raw material costs and the prices paid by Hawaiian Electric for fabricated materials; and (d) the methods Hawaiian Electric utilizes to manage the total expense of its maintenance activity such that increased material prices tends to result in less work being performed and vice versa. Accordingly, Hawaiian Electric considers the maintenance materials estimate of $8,871,000 incorporated in the Company's Statement of Probable Entitlement to be reasonable and it should not be adjusted.

Q. Does this conclude your testimony?

A. Yes.

HAWAIIAN ELECTRIC COMPANY, INC.
2009 Rate Case
Docket No. 2008-0083
Rate Case Expense Summary

	Settlement	Settlement Adjustments	Update	Update Adjustments	Direct Testimony	May 2009 Recorded YTD	Recorded 2008	Recorded 2007	2007 TY Interim
Production									
Labor	33,123,000	(316,000)	33,439,000	427,000	33,012,000	12,957,000	29,090,000	26,373,000	29,267,000
Non-Labor	45,850,000	(4,278,000)	50,128,000	2,749,000	47,379,000	15,723,000	48,278,000	42,434,000	38,330,000
Total	78,973,000	(4,594,000)	83,567,000	3,176,000	80,391,000	28,680,000	77,368,000	68,807,000	67,597,000

HAWAIIAN ELECTRIC COMPANY, INC.
2009 Rate Case
Docket No. 2008-0083
Rate Case Expense Summary

	Settlement	Settlement Adjustments	Update	Update Adjustments	Direct Testimony	May 2009 Recorded YTD	Recorded 2008	Recorded 2007	2007 TY Interim
Production Operations									
Labor	15,632,000	(197,000)	15,829,000	427,000	15,402,000	6,554,000	15,021,000	13,394,000	13,959,000
Non-Labor	16,930,000	(2,771,000)	19,700,000	2,702,000	16,998,000	5,787,000	15,757,000	14,413,000	14,900,000
Subtotal	32,562,000	(2,967,000)	35,529,000	3,129,000	32,400,000	12,341,000	30,777,000	27,807,000	28,859,000
Production Maintenance									
Labor	17,491,000	(119,000)	17,610,000	-	17,610,000	6,403,000	14,069,000	12,979,000	15,308,000
Non-Labor	28,920,000	(1,508,000)	30,428,000	47,000	30,381,000	9,935,000	32,521,000	28,021,000	23,430,000
Subtotal	46,411,000	(1,627,000)	48,038,000	47,000	47,991,000	16,338,000	46,590,000	41,000,000	38,738,000
Production O&M Total									
Labor	33,123,000	(316,000)	33,439,000	427,000	33,012,000	12,957,000	29,090,000	26,373,000	29,267,000
Non-Labor	45,850,000	(4,278,000)	50,128,000	2,749,000	47,379,000	15,723,000	48,278,000	42,434,000	38,330,000
Total	78,973,000	(4,594,000)	83,567,000	3,176,000	80,391,000	28,680,000	77,368,000	68,807,000	67,597,000

PRODUCTION
Operation & Maintenance Expense

TOPIC

1. Production Operation Expense

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Responses to Information Requests	CA-IR-306	
1q. CIP CT-1 Operating Expenses		
Responses to Information Requests	CA-IR-391	
1r. Technical Services Charges		
Responses to Information Requests	CA-IR-459	
1s. PJC Chemicals Materials		
Responses to Information Requests	CA-IR-460	
1t. Clean Island Council		
Responses to Information Requests	CA-IR-462	
1u. EMIS Air Quality Modules		
Responses to Information Requests	CA-IR-463	
1v. PNR R&D Spending		
Responses to Information Requests	CA-IR-464	
1w. PV Host New Position		
Responses to Information Requests	CA-IR-465	
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1x. CIP CT-1 Water Plan		
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1y. Power Supply Engineering Project Manager		
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2. Production Maintenance Expense

2a. Production Maintenance Labor Expense Increase		
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2b. Production Maintenance Non-Labor Expense Increase		
Direct Testimony	HECO T-7	Pages 100-104
2c. Normalized Planned Maintenance Schedule		
Responses to Information Requests	CA-IR-69	
2d. Supplemental Labor		
Responses to Information Requests	CA-IR-74	
2e. Station Maintenance and Overhaul Trends		
Responses to Information Requests	CA-IR-75	

2f. Vacant "Replacement" Positions		
Responses to Information Requests	CA-IR-77	
2g. Power Supply O&M Program		
Responses to Information Requests	CA-IR-188	
2h. RA=PIZ Non-Labor CIP CT-1 Unit Charges		
Responses to Information Requests	CA-IR-208	
2i. RA=PIX Non-Labor Charges		
Responses to Information Requests	CA-IR-209	
2j. RA=PIL Non-Labor Charges		
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2k. Station Maintenance		
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1l. Biofuels Outside Engineering		
Responses to Information Requests	CA-IR-295	
Rate Case Update	HECO T-7	Pages 44-45
2m. Maintenance Division Labor and Supplemental Labor		
Responses to Information Requests	CA-IR-304	
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2n. Maintenance Expense Comparisons		
Responses to Information Requests	CA-IR-307	
2o. Maintenance Non-Labor Expense Comparisons		
Responses to Information Requests	CA-IR-308, -309	
2p. CIP CT-1 Facilities Repair Expenses		
Responses to Information Requests	CA-IR-390	
2q. Production Maintenance Expense		
Responses to Information Requests	CA-IR-392	
2r. Honolulu PIN Asbestos Removal		
Responses to Information Requests	CA-IR-461	
2s. Production Maintenance Labor and Non-Labor		
Responses to Information Requests	CA-IR-470	
3. Production Operation & Maintenance Expense		
3a. Cost Trend		
Direct Testimony	HECO T-7	Pages 104-107
3b. CIP CT-1 Step Increase		
Direct Testimony	HECO T-7	Pages 107-113

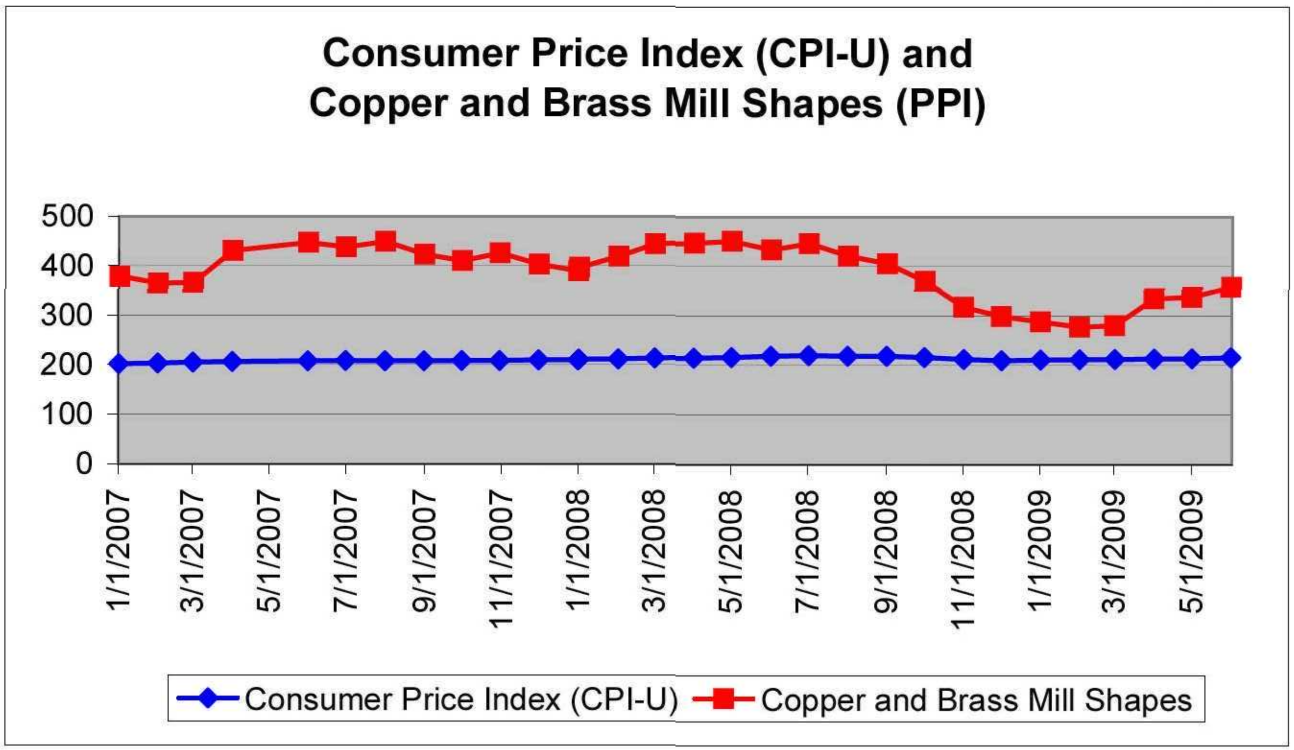
3c. Production Variance Direct Testimony	HECO T-7, HECO-P-701	Pages 1-12
3d. Power Supply Staffing Responses to Information Requests	CA-IR-70	
3e. Overtime Responses to Information Requests	CA-IR-73	
3f. Training Efforts/Costs Responses to Information Requests	CA-IR-85, -195, -305	
3g. RA=PIB Non-Labor Charges Responses to Information Requests	CA-IR-201	
3h. CIP CT-1 O&M Expense Projections Responses to Information Requests	CA-IR-297	
3i. Production O&M Expense Comparisons Responses to Information Requests	CA-IR-312	
4. Inventory		
4a. Production Materials Inventory Direct Testimony	HECO T-7, HECO-WP-702	Pages 113-115
4b. Power Supply Materials & Stores Inventory Responses to Information Requests	CA-IR-455	

Hawaiian Electric Company, Inc.
2009 Rate Case
Consumer Price Index (CPI-U) and Copper and Brass Mill Shapes Price Indexes (WPU102502)
(data extracted on 07/15/09)

	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08
Consumer Price Index (CPI-U)	202.4	203.5	205.4	206.7	207.9	208.4	208.3	207.9	208.5	208.9	210.2	210.0	211.1	211.7	213.5
Copper and Brass Mill Shapes	379.2	365.0	366.1	431.0	447.3	438.3	448.9	423.0	410.2	426.0	402.9	389.8	396.9	419.1	444.6

	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09
Consumer Price Index (CPI-U)	214.8	216.6	218.8	220.0	219.1	218.8	216.6	212.4	210.2	211.1	212.2	212.7	213.2	213.9	215.7
Copper and Brass Mill Shapes	447.0	450.9	433.5	446.6	421.2	405.6	370.0	318.1	298.9	288.1	277.8	280.1	334.8	337.6	357.7
												(P)	(P)	(P)	(P)

(P) = Preliminary



Source: U.S, Department of Labor - Bureau of labor Statistics - Consumer Price Index & Series Report (as used in HECO-745 and response to CA-IR-310).

HECO ST-8
DOCKET NO. 2008 - 0083

SUPPLEMENTAL TESTIMONY OF
ROBERT K. S. Y. YOUNG

MANAGER
SYSTEM OPERATION DEPARTMENT
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Transmission and Distribution Operations and Maintenance Employee Counts

INTRODUCTION

Q. Please state your name and business address.

A. My name is Robert Young and my business address is 820 Ward Avenue, Honolulu, Hawaii.

Q. Please state what testimony you are providing.

A. I am providing supplemental testimony for the Transmission and Distribution ("T&D") Operations and Maintenance ("O&M") employee counts as discussed in Section III(a) of the Commission's the Interim Decision and Order for HECO Docket 2008–0083. Also, to address Section III(j) of the Interim Decision and Order and to assist the Commission's review of the evidence concerning significant expense increases between the 2007 test year interim award and the 2009 test year, I have provided HECO-S-802 as part of my supplemental testimony. HECO-S-802 is a compilation of references to the record in this proceeding (Direct Testimony and Exhibits, IR responses and Rate Case Updates) of the evidence supporting expense increases.

Q. What additional information are you providing in support of HECO's employee count?

A. Following is a discussion of the staffing changes that have occurred using the 2007 recorded end of year (EOY) employee count as the starting point. In my testimony I will explain the year over year changes that occurred from 2007 to June 30, 2009 and provide an update on the actual staffing levels compared to those identified in the settlement agreement.

Q. What specific areas are covered in your testimony?

A. My testimony will cover the Energy Delivery Process Area (EDPA) that consists of the following departments, Construction and Maintenance (C&M), System

Operation (SOD), Support Services, and Engineering.

Q. Were there any company wide organizational changes that affected the employee counts for the departments that contribute to T&D O&M expenses?

A. Yes, between 2007 and 2009 there were several organizational changes that occurred and some of those changes involved EDPA. The largest change in terms of the number of employees involved the assignment of the Customer Installations Department (CID) to the process area responsibility of the Vice President, Energy Delivery. In this reassignment 55 employees were moved into EDPA in February 2009. Subsequently, additional changes to the organization were made to ensure the successful completion of the tasks identified in the Hawaii Clean Energy Initiative (HCEI) Energy Agreement. As a result, the System Protection section consisting of 4 filled positions and the Distribution Planning Division consisting of 7 filled positions from the Engineering department were transferred to the newly formed Systems Integration department. In addition to these 11 filled positions from Engineering, 6 positions (but only 4 were filled) assigned to work on AMI that resided in the Customer Installations department were also transferred to the Systems Integration department. In February 2009, CID was moved to the Customer solutions Process Area. However, the AMI section remained in the Systems Integration Department for reasons discussed previously (Mr. Leon Roose, HECO T-15C, provides additional testimony in support of the organizational changes that were made to transfer these different groups of employees into his department).

The Energy Delivery area saw one more change in the corporate reorganization when the Purchasing Division in the Support Services department consisting of 15 filled positions was transferred to the Finance and Administration

Process Area to consolidate employees with financial responsibility into the same process area. However as discussed in the supplemental testimony provided by Ms. Faye Chiogjioji, HECO ST-15, since there were no changes to employee counts, labor expense requirements or block of accounts, for the purpose of comparing the history of positions on a consistent basis, we will discuss staffing based on the organization prior to the reorganizations covered in her supplemental testimony. Therefore to maintain a consistency in the process area staffing count when comparing the changes from year to year these moves will be treated as if the EDPA continued with the organization in place with CID as part of the process area.

Q. Before you cover the staffing changes in the period between 2007 and 2009; please explain why is it important for HECO to increase its staffing levels?

A. In my direct testimony and in the November 2008 rate case update I identified the reasons why it was necessary to increase the staffing levels for the EDPA departments. One reason for the higher staffing numbers is simply the labor hours necessary to maintain the system and the labor demand for capital projects are significantly greater than what the existing workforce can provide. (See HECO T-8 starting at page 13, CA-IR-220 and CA-IR-314). As explained in my direct testimony, the combined hourly needs for system maintenance and capital projects have consistently been greater than what the workforce is able to provide without unreasonable levels of overtime. Notwithstanding the impact of the declining economic conditions in Hawaii, resulting in lower electric sales, the transfer of some of the energy efficiency programs to SAIC (Science Application International Corporation), and the possible disallowance of HECO's new generating unit CIP CT1, the wear and tear on HECO's equipment and aging of

HECO's infrastructure continues. The impact of the trends cited by the Commission in Section III(a) of its Interim Decision and Order will not permit HECO to discontinue operation and maintenance of transmission and distribution lines and substations. . Automobile accidents will continue to cause outages, the trees and other vegetation will continue to grow and HECO's electrical infrastructure will continue to operate 24 hours a day 7 days a week, 365 days a year. As discussed in my direct testimony, some of the equipment on the system is more than 30 years old and has therefore lasted beyond the average life of that type of equipment. To prevent a decline in reliability levels (that is, longer and more frequent outages), it is important that the system continue to be maintained and that older equipment be replaced to prevent unexpected failures from occurring.

Q. Has HECO taken any new steps to address the aging assets?

A. A new Asset Management group was formed to oversee the efforts of the EDPA departments to address the aging assets. Therefore it's important that HECO have the skilled workforce necessary to perform the work. In areas such as C&M and SOD, developing a skilled workforce may take as long as 3 to 5 years. In my direct testimony, HECO T-8, pages 18 - 19, I discussed the C&M lineman apprentice program, and explained that it takes 3 years for the employee to complete the apprenticeship program. After graduating from the program it may be another 2 or 3 years for the employee to continue developing his/her skills for performing the work on the electrical system. Because of the inherent dangers of working on high electrical voltages and under the demanding conditions of the job it's important that the workforce be adequately trained.

Q. Why is more time required to perform maintenance on the system?

A. More areas on Oahu are being developed or redeveloped such that the electrical infrastructure is also growing. More time is required to maintain the system because, as the system grows, there are more substations, transformers, circuit breakers, relays, and other electrical equipment that must be inspected and maintained. The growth of the system was demonstrated in HECO-817 which showed the growth of T&D plant in service. Without having the additional work force to support the growing system, then maintenance will suffer which could increase the number of outages.

Q. How will the integration of renewable energy affect the Energy Delivery Process Area?

A. We have begun the effort to address the Hawaii Clean Energy Initiative that calls for the reduction in the use of fossil fuels for electricity. Adding a larger proportion of renewables to the HECO system will introduce the intermittent flow of electrical power that potentially can affect the entire island and all of HECO's customers. As we analyze the impacts of the renewable energy sources as well as the infrastructure changes (such as AMI and the smart grid initiatives) system changes or additions are likely to be needed which, in turn, will increase the workload in EDPA and the need for additional staff to perform the work. Moreover, in order for HECO to be able to accept power from renewable sources, it has to ensure that the existing infrastructure is capable of accepting the power.

<u>2007 – 2009 STAFFING STATUS</u>

Q. What was the staffing increase that occurred between the 2007 and 2009 rate case test years?

A. Comparing the 2007 and 2009 staffing levels within the Energy Delivery Process Area is not easily accomplished because, as discussed in HECO ST-15 and HECO

ST-1, during this period there were several re-organizations. Therefore, to facilitate the explanation my testimony presents two tables. The first table, HECO-S-1510 (Without Re-Org), compares the 2007 rate case settlement test year average and the 2009 rate case update test year average in the Energy Delivery Process Area as if March 2009 reorganization had never taken place. The second table, HECO-S-1511 (With Re-Org), compares the 2007 settlement test year average and the 2009 rate case update test year average in the Energy Delivery Process Area as if the re-organizations, including the one effective March 2, 2009, were in effect in both 2007 and 2009. Providing these two illustrative tables facilitates a consistent, "apples-to-apples" comparison of both the historical and current company organizations. In both cases, the respective overall employee headcounts for the 2007 rate case settlement and 2009 rate case update did not change, as demonstrated in HECO ST-15. In HECO-S-1511 "With Re-Org" the 2009 average staffing level for EDPA is 490 employees based on the 2009 test year rate case November update compared to the 2007 adjusted test year settlement average of 474 positions. As indicated in the note at the bottom of the table the "adjustment" is made to reflect the employee count averages calculated as if the reorganization was in place for both the 2007 settlement and the 2009 rate case update. The table shows that average employee count increased by 16 positions from 2007 to 2009. Exhibit HECO-S-1511 also shows that actual employee count of 492 as of June 30, 2009 with the adjustment made for the reorganization is greater than both the 2007 settlement test year and 2009 update test year averages.

A similar analysis was done to compare the employee count for EDPA without the reorganization that occurred in 2009 and this is shown in HECO-S-

1510 (Without Re-Org). The assumptions in this analysis are that CID continues to be a part of EDPA and includes the AMI employees and that the employees in Distribution Planning and System Protection remain in the Engineering department in EDPA. This exhibit (HECO-S-1510) shows that without the reorganization the employee counts for the 2007 test year settlement average is 549 employees and the 2009 update test year average equals 571 employees. This resulted in a difference of 22 employees between the 2007 test year settlement average and the 2009 test year update average. When comparing the actual June 30, 2009 employee count without considering the impact of the reorganization EDPA's staffing total is 570 employees compared to the 2009 test year update end of year total of 572 employees.

Q. How long does it take for EPDA to fill vacancies?

A. I have prepared HECO-S-801 to show that the vacant positions identified in the 2007 test year and 2009 test year rate cases are usually filled within the test year period. HECO-S-801 indicates that, of the vacant positions that were anticipated to exist in the beginning of the 2007, 17 of the 19 vacant positions were filled within the year.

HECO successfully hired to fill the majority of the vacant positions but at year end was 11 positions short of meeting the test year total of 509 employees. (Note that the 509 employees exclude the CID employees and if the CID employees were included in the EDPA count there would be 559 employees at year end 2007. The end of year employee count for CID was obtained from HECO-S-1511.) These 11 vacancies were the result of employee's transferring or terminating their service with HECO. However as Exhibit HECO-S-1510 shows, the end of year 2008 employee count for EDPA increased to 552 employees or 4 employees more than the 2007 end of year count of 548 (that includes CID's 50 employees shown in HECO-S-1511 at 2007 year end).

In HECO T-8 direct testimony, Docket No. 2008-0083, for the 2009 test year rate case the EDPA employee count total excluding CID was projected to be 510 employees. Exhibit HECO-S-1510 shows there are an additional 55 employees from CID resulting from the corporate reorganization that assigned CID to Energy Delivery, 2 additional employees in C&M and 5 more employees in the System Operation department identified in the 2009 test year rate case update which raised the total to 572 for the process area. The additional employees for C&M and System Operation were described in the 2009 rate case update for Docket No. 2008-0083 filed in November 2008. As of June 30, 2009 the Energy Delivery Process area had 570 employees or just 2 employees less than the rate case update year end amount.

Q. Will the departments be able to fill all the positions in 2009?

A. Yes, the departments with vacancies remaining expect to recruit and fill the positions in 2009. There is a need to fill the open positions because as discussed in my supplemental testimony there are a number of initiatives and projects currently on-going that will need to be addressed. The work is not expected to diminish because absent any new projects there is still an abundant need to maintain the existing system and all the positions in the process area play an integral role for the planning and engineering of the electrical system.

Q. Will the lower staffing numbers you discussed above as it relates to the March 2, 2009 reorganization's impact the T&D O&M expenses put forward in your direct testimony and the November update?

A. Though several areas were affected (CID, Distribution Planning, System

Protection, Purchasing) the employees in those part of the organization will continue to perform the same functions that they provided to the process area before the reorganization. As a result they will continue to charge the same code blocks though with different responsibility area RA's but the charges will continue to flow where they would have had the reorganization not been done. Therefore as Ms. Chiogioji points out there was no impact to the block of accounts resulting from the reorganization.

Q. Does this conclude your testimony?

A. Yes it does.

2007 TEST YEAR VACANCIES (N.1)				2007 Vacancies Filled	Vacancies Filled in 2008
Department	Vacancies	Positions	Status		
C&M	2	Senior Helper	Filled 1/22/07	2	
Engineering	1	Telecomm Engineer	Filled 2/20/07	1	
Support Services	4	1 - Contract Administrator	Filled 3/05/07	1	
		1 - Service Station Attendent	Filled 1/02/07	1	
		2 - Mechanics	Filled 4/2/07, 6/18/07	2	
				1	
System Operation	12	1 - Technical Trainer	Filled 2/18/08		1
		2 - EFMS Technicians	Filled 1/29/07, 3/1/07	2	
		1 - Substation Electrician	Filled 1/8/07	2	
		1 - System Coordinator	Filled 6/11/07 (replaced with Operating Engineer)	1	
		1 - Reliability Analyst	Filled 4/27/09		
		1 - Switching Coordinator	Filled 2/19/07	1	
		2 - Trouble Dispatchers	Filled 5/14/07, 6/18/08	1	1
		1 - PDM Specialist			
		1 - Mapping Division Supervisor	Filled 2/12/07	1	
		1 - Director Special Projects	Filled 2/5/07	1	
Total	19			17	2

2009 TEST YEAR VACANCIES (N.2)				2009 Vacancies Filled
Department	Vacancies	Positions	Status	
C&M	7	Senior Helper	Filled 7/14/08, 10/27/08	7
Engineering	1	Temporary Vacancy - Job Rotation		
Support Services	1	1 - Automotive Attendent	Filled 6/18/08	1
System Operation	3	1 - Systems Engineer	Filled 3/09/09	1
		1 - Trouble Dispatcher	Filled 1/19/09	1
		1 - Construction Journeyman	Filled 10/31/08	1
Total	12			11

2009 TEST YEAR UPDATE VACANCIES (N.3)				2009 Vacancies Filled
Department	Vacancies	Positions	Status	
C&M	2	1 - Senior Construction Manager	Filled 10/27/08	1
		1 - Resource Planner	Filled 2/9/09	1
Engineering	0			
Support Services	0			
System Operation	5	1 - Asset Management Manager	Filled	1
		2 - Asset Management Directors	Filled 1 - 12/22/08, 1 - 5/25/099	2
		2 - Asset Management Program Managers	Filled 1 -	1
CID	5	1 - AMI Director	Filled 7/2/07	1
		1 - AMI Project Manager	5/12/08	1
		1 - AMI System Administrator	Filled 9/3/07, 7/7/08	1
		1 - AMI Project Engineer		
		2 - AMI Systems Engineer	Filled 2/2/09	1
Total	12			10

N.1 Number of vacancies are the difference between the "2006 EOY Projected" column and the "Test Year Estimate" column shown in HECO-725, page 1, submitted in Hawaiian Electric's 2007 Test Year Rate Case, Docket No. 2006-0386.

N.2 Number of vacancies are shown in the table in HECO T-8, Page 18, and discussed on pages 17-20, HECO T-8, of the instant proceeding.

N.3 Vacancies are described on page 9 of Rate Case Update, HECO T-8, page 9, and discussed on pages 8-9 of the instant proceeding.

TRANSMISSION & DISTRIBUTION (T&D)		
Operation & Maintenance Expense		
TOPIC		
1. Transmission Operation Expense		
Overall	HECO T-8	Pages 24-25
Stipulated Settlement Letter (filed 5/15/09)	Exhibit 1, Section 16	Pages 33-36
1a. Interconnection Requirement Studies		
Direct Testimony	HECO T-8	Pages 25-26
1b. Transmission System Inspections		
Direct Testimony	HECO T-8	Pages 26-27
1c. Siemens Energy Management System (EMS) Maintenance		
Direct Testimony	HECO T-8	Pages 27-29
1d. Dispatcher Training		
Direct Testimony	HECO T-8	Pages 29-30
1e. Outside Services for Transmission Station Work		
Direct Testimony	HECO T-8	Pages 30-31
2. Transmission Maintenance Expense		
Overall - Direct Testimony	HECO T-8	Pages 31-32
Responses to Information Requests	CA-IR-87-91	
2a. Vegetation Management		
Direct Testimony	HECO T-8	Pages 32-39
2b. Outside Contractors - Communications Section		
Direct Testimony	HECO T-8	Pages 39-40
2c. Outside Contractors - Substation Section		
Direct Testimony	HECO T-8	Pages 40
2d. Substation Rust Maintenance		
Direct Testimony	HECO T-8	Pages 41-44
3. Distribution Operation Expense		
Overall - Direct Testimony	HECO T-8	Pages 45-46
3a. Outage Management System (OMS)		
Direct Testimony	HECO T-8	Pages 46-50
Responses to Information Requests	CA-IR-104	
3b. Preventive Inspections		
Direct Testimony	HECO T-8	Pages 50-51
3c. New Metering Technology (AMI)		
Direct Testimony	HECO T-8	Pages 52-54
Rate Case Update	HECO T-8	Pages 4-6
Responses to Information Requests	CA-IR-105, 216-219, 265, 440-447	
Stipulated Settlement Letter (filed 5/15/09)	Exhibit 1, Section 11, 11a, 16e	Pages 18-21, 37

TRANSMISSION & DISTRIBUTION (T&D)		
Operation & Maintenance Expense		
3d. PTM Switching Operations		
Direct Testimony	HECO T-8	Pages 54-57
3e. CIS Training		
Direct Testimony	HECO T-8	Pages 57-58
Responses to Information Requests	CA-IR-106	
Stipulated Settlement Letter (filed 5/15/09)	Exhibit 1, Section 14, 16.g	Pages 25-27, 37
4. Distribution Maintenance Expense		
Overall - Direct Testimony	HECO T-8	Pages 58-60
Responses to Information Requests	CA-IR-92	
4a. Vegetation Management - Distribution		
Direct Testimony	HECO T-8	Page 60
Responses to Information Requests	CA-IR-99-103	
4b. Wood Pole Repair & Replacement		
Direct Testimony	HECO T-8	Pages 60-61
4c. Wood Pole - Test & Treat		
Direct Testimony	HECO T-8	Page 61
5. T&D Materials Inventory		
Overall - Direct Testimony	HECO T-8	Pages 62-64
Responses to Information Requests	CA-IR-107, 313	
Stipulated Settlement Letter (filed 5/15/09)	Exhibit 1, Section 29	Page 70
Response to Interim D&O (filed 7/8/09)	Exhibit 3, Section II.2.(d)	Pages 14-17
6. Employees & Labor Costs		
Overall - Direct Testimony	HECO T-8	Pages 13-23
Responses to Information Requests	Responses to CA-IR-95-98, 314,471	
6a. C&M Employee Additions	Rate Case Update	Pages 1-4
6b. Asset Management Group	Rate Case Update	Pages 6-8
6c. Vacancy Rate and Labor Expense Adjustment -		
Stipulated Settlement Letter (filed 5/15/09)	Exhibit 1, Section 12	Page 22-24
6d. Merit Salary Reduction -		
Stipulated Settlement Letter (filed 5/15/09)	Exhibit 1, Section 13, 16f	Page 24-25, 37
6e. Payroll & Benefits		
Stipulated Settlement Letter (filed 5/15/09)	Exhibit 1, Section 16a	Page 36
7. Budget Process		
Overall - Direct Testimony	HECO T-8	Pages 10-17
Responses to Information Requests	CA-IR-93-94, 314, 471-472	
8. Contract Services		
Responses to Information Requests	CA-IR-99, 220, 314	
9. Nonlabor Costs - Overall (Response to IR)	CA-IR-472	

TRANSMISSION & DISTRIBUTION (T&D)				
Operation & Maintenance Expense				
	9a.	Vehicle Fuel On-Cost Expenses - Stipulated		
		Settlement Letter (filed 5/15/09)	Exhibit 1, Section 9 and 16d	Pages 16-17, 37
	9b.	General Inflation Factor - Stipulated		
		Settlement Letter (filed 5/15/09)	Exhibit 1, Section 10 and 16c	Pages 17-18, 37
	9c.	Abandoned Projects Normalization -		
		Settlement Letter (filed 5/15/09)	Exhibit 1, Section 16b	Pages 36
10. Vegetation Management - Transmission & Distribution				
	Direct Testimony		HECO T-8	Pages 32-39, 60
	Responses to Information Requests		Responses to CA-IR-99-103	

SUPPLEMENTAL TESTIMONY OF
DARREN S. YAMAMOTO

MANAGER
CUSTOMER SERVICE DEPARTMENT
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Customer Accounts Employees
Allowance for Uncollectible Accounts

INTRODUCTION

Q. Please state your name and business address.

A. My name is Darren S. Yamamoto and my business address is 900 Richards Street, Honolulu, Hawaii.

Q. By whom are you employed and in what capacity?

A. I am the Manager of the Customer Service Department for Hawaiian Electric Company, Inc. ("HECO"). My experience and educational background are listed in HECO-900. I have previously submitted written direct testimony in this case as HECO T-9. I am also submitting supplemental testimony as HECO ST-9.

Q. What is the scope of your supplemental testimony?

A. My supplemental testimony will support the employee headcount growth for the Customer Service Department from the 2007 Test Year Settlement to the 2009 Test Year Settlement. I will also address the allowance for uncollectibles issue stated in the Interim Decision and Order ("ID&O") of this rate case.

Customer Accounts Employee Count

Q. What were the estimated Customer Service average employee counts for the 2007 and 2009 Test Years as provided in their respective settlement agreements?

A. The estimated employee counts are provided below. I have also included the actual employee counts for 2007 yearend, 2007 average, 2008 yearend, and as of June 30, 2009, which are reflected in Ms. Faye Chiogioji's exhibit, HECO-ST-1503. The employee counts are as follows:

2007 Settlement TEST YEAR average	131

2007 Year-End Actual	136
2007 Actual Year Average	132
2008 Year-End Actual	150
2008 Actual Average	141
2009 Settlement TEST YEAR average	148
2009 Actual as of June 30, 2009	140

Q. What is the difference between the Settlement 2007 Test Year Average and the 2009 Update Test Year Average?

A. The 2009 Test Year Average is an increase of 17 over the 2007 Test Year Average.

Q. What makes up the 17 increase in the employee count?

A. The 17 increase in the employee count is made up of 14 HECO Temp positions and 3 new regular employee positions. The labor cost of the 14 HECO Temp positions (described as "Summer Interns" and "Summer Hires") are found in the Company's response to CA-IR-1, HECO T-9, Attachment 2, page 12 and page 43.

Q. Why were so many HECO Temp positions required?

A. The HECO Temp positions consisted of 11 temporary meter readers and three temporary payment processing and customer accounting and billing temporary employees. As noted in my direct testimony, HECO T-9, page 8, these temporary workers were required as replacements of regular staff that were assigned to the Customer Information System ("CIS") project. Although CIS was planned to be placed into service in May 2009, the HECO Temps were required to also assist during the transitional period after the CIS cutover.

Q. What are the three additional regular positions?

A. The three additional regular positions are for an operations analyst, call center supervisor, and a revenue protection investigator.

Q. What was the actual employee headcount of the Customer Service Department as of June 30, 2009?

A. On June 30, 2009, the actual employee headcount was 140. This is eight employees less than the 2009 Update Test Year Average.

Q. Are all of the eight vacancies the HECO Temp vacancies?

A. Yes. Because the Company is reassessing the testing plan for the CIS, a portion of the regular employees have returned to their regular positions and we have released the temporary meter readers. The Company's response to CA-IR-323, part c, discusses the impact of the delay of the implementation of CIS on the 2009 test year. Revised exhibits HECO-907 and HECO-908 that were submitted in the response to CA-IR-323 as Attachments 1A and 2 reflect the removal of the CIS expenses except for reclassified on-costs and payroll taxes, including the continued deferral of labor costs associated with regular employees that would continue testing throughout the test year. However, with the slowing of testing, many of these regular employees have returned to their normal assignments, resulting in the release of the HECO temps. This results in no change to O&M expenses since the regular employees' and HECO temp costs offset one another but will result in less deferred CIS project expenses than anticipated.

<u>Customer Accounts' Allowance for Uncollectibles</u>

Q. What does the ID&O say with respect to the allowance for uncollectibles?

A. The ID&O, "(t)he commission notes that there appears to be significant increases in certain expenses between the 2007 test year interim award to the 2009 test year in the areas of . . . allowance for uncollectibles. . . . These areas may be subject to further examination by the commission." (ID&O at 16)

Q. What are the 2007 test year interim award and the 2009 test year settlement amounts for allowance for uncollectibles?

A. The 2007 test year interim award for uncollectibles was $970,000. The 2009 test year settlement amount was $1,302,000 for an increase of 34 percent between 2009 and 2007 rate cases.

Q. Why is this a reasonable increase?

A. The support provided by Hawaiian Electric for the $1,302,000 uncollectibles amount in this 2009 rate case are as follows:

1. Both the 2007 and 2009 rate case test year settlement amounts of $970,000 and $1,302,000 are based on the same methodology of using five years of data to calculate an estimated net write-off percentage for the test year. In fact, the same percent net write-off of .0719 percent was used to calculate the uncollectibles amount in both the 2007 and 2009 rate case settlements. (2007 Stipulated Settlement letter, Exhibit 1, page 11; HECO T-9, page 25) While the parties in both rate cases agreed to the absolute amounts, these amounts were nonetheless derived using the same methodology and the same percent

net write-off. This percent of electric sales revenues method has been accepted by the Commission in other rate cases (HECO T-9, page 26).

2. The 2008 uncollectibles accounts expense recorded was $3.646,452. (Company's response to CA-IR-389; Stipulated Settlement Letter, Exhibit 1, page 41) This is 180 percent more than the 2009 test year settlement amount, so the amount requested of $1,302,000 for the 2009 test year is reasonable.
3. In the Stipulated Settlement Letter, Hawaiian Electric provided information which supported higher uncollectibles than the settlement amount. For the first three months of 2009, uncollectibles were $491,486, or $1,965,944 computed on an annualized basis. (Stipulated Settlement Letter, HECO T-9, Attachment 1) The annualized amount is over 50 percent more than the 2009 test year uncollectibles amount of $1,302,000.
4. Past and continued trends of economic downturns support a higher uncollectibles expense amount. Information on bankruptcies or non-payment write-offs over $50,000 from 2006 through 2008 (preliminary) demonstrated this trend. (Company's response to CA-IR-319) This is further exemplified by recent newspaper articles on bankruptcies and foreclosures.[1]

Q. Is there updated Company information to indicate that the 2009 uncollectibles expense amount is reasonable?

[1] See *Hawaii Bankruptcies hit 44-month high in June*, Honolulu Advertiser.com, July 1, 2009; *Worst in foreclosures yet to come?*, Honolulu Star-Bulletin, July 16, 2009.

A. Recent data shows that, for January through May 2009, the uncollectibles expense amount is [redacted]. On an annualized basis, this translates to an estimated uncollectibles amount of about [redacted], which is [redacted] percent over the 2009 settlement amount. See HECO-S-901.

All the above demonstrates that the 2009 uncollectibles expenses of $1,302,000 is reasonable.

Q. Does this conclude your supplemental testimony?

A. Yes, it does.

Confidential Information Deleted Pursuant To Protective Order, Filed on November 21, 2008.

NARUC ACCOUNT 904 UNCOLLECTIBLES

	Actual 2008		Actual 2009
Jan	$ 74,695	Jan	$ 143,550
Feb	$ 39,871	Feb	$ 69,210
Mar	$ 125,264	Mar	$ 278,726
Apr.	$ 72,714	Apr	[redacted]
May	$ 53,512	May	
Jun	$ 104,146		
Jul	$ 95,534		
Aug	$ 169,406		
Sep	$ 691,901		
Oct	$ 229,957		
Nov	$ 1,740,615		
Dec	$ 280,690		
TOTAL	**$ 3,678,306**	**YTD**	[redacted]
		ANNUALIZED	

Note: 2008 information differs slightly from the response to CA-IR-389 as the information previously provided were based on preliminary information.

Source: Ellipse MSO963 screen, NARUC Account 904,

HECO ST-10
DOCKET NO. 2008-0083

SUPPLEMENTAL TESTIMONY OF
ALAN K.C. HEE

MANAGER
ENERGY SERVICES DEPARTMENT
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Customer Solutions Head Count,
Base Demand-Side Management Expenses

INTRODUCTION

Q. Please state your name and business address.

A. My name is Alan K.C. Hee and my business address is 220 South King Street, Honolulu, Hawaii.

Q. By whom are you employed and in what capacity?

A. I am the Manager of Hawaiian Electric Company, Inc.'s ("Hawaiian Electric", "HECO", or "Company") Energy Services Department ("ESD").

Q. What is your educational background and professional experience?

A. My experience and educational background are listed in HECO-1000.

Q. What is your area of responsibility in this supplemental testimony?

A. My supplemental testimony will cover (1) HECO's 2009 test year estimate of the Customer Solutions Process Area headcount, and (2) the increase in base Demand Side Management ("DSM") expenses.

CUSTOMER SOLUTIONS PROCESS AREA HEADCOUNT
(Ref. Section III.(a) Interim Decision & Order

Q. Why are you addressing headcount in this supplemental testimony?

A. In its Interim Decision and Order ("ID&O"), the Commission required additional information from Hawaiian Electric to determine whether the increase in the number of employees between 2007 and 2009 is reasonable. Comparing the 2007 and 2009 staffing levels within the Customer Solutions Process Area is not easily accomplished because there were several re-organizations during this period. HECO ST-15 and Exhibits HECO-S-1510 and 1511 discuss these reorganizations in further details. Therefore, my supplemental testimony presents two tables. The first compares the 2007 rate case settlement test year average and 2009 rate case update test year average in the Customer Solutions Process Area as if the March 2009 reorganization had never taken place (see Exhibit HECO-S-1001). The second table compares the 2007 settlement test year average versus the 2009 rate case update average in the Customer Solutions Process Area as if the reorganizations, including the one in March 2009, were in effect in both 2007 and 2009 (see HECO-S-1002). Providing these two illustrations permits a consistent, "apples-to-apples" comparison of both the historical and new company organizations.

Q. What is the test year Customer Solutions Process Area headcount if the March 2009 reorganization did not take place?

A. The 2009 test year head count for the process area is 50 if the March 2009 reorganization did not take place, as shown in Exhibit HECO-S-1001. This is a decrease of one position from the headcount proposed by HECO in its 2007 test year rate case. However, in the September 5, 2007 settlement agreement reached by the parties to the 2007 test year rate case (Consumer Advocate, the Department of Defense, and HECO), the headcount for the Energy Services Department was decreased by six positions. These positions were, at that time, related to the administration of energy efficiency programs that the Commission had determined were to be transitioned to a third-party public benefit fund ("PBF") Administrator.

Q. What is the effect on the revised difference if the six positions are removed from the 2007 test year rate case headcount?

A. The 2009 test year rate case headcount remains at 50, however, it now represents an increase of five positions over the 2007 test year rate case headcount, as shown in the table at the bottom of Exhibit HECO-S-1001.

Q. Please explain the increase of the five positions.

A. The increase results from an increase of three positions in the Energy Services Department ("ESD"), and one position each in the Marketing Services Division and VP-Customer Solutions office.

Q. Why is the ESD headcount increasing by three positions?

A. One position currently exists as an incremental position in the Customer Efficiency Programs ("CEP") Division, but is being proposed to be recovered in base rates as discussed in direct testimony (see HECO T-10, pages 19 and 58). Two positions are the result of adding two Senior Rate Analysts ("SRAs") in the Pricing Division. One of the two SRAs was included in my direct testimony in this docket (see HECO T-10, page 9 to 11); the second SRA was added in HECO's rate case update in November 2008 (see Rate Case Update, HECO T-10, pages 4-7). All three positions have been filled and were added to handle increased workload related to base rate activities.

Q. Why is it reasonable to increase the CEP Division base rate headcount when the energy efficiency programs have been transferred to a third-party administrator?

A. It is reasonable to add a CEP Analyst position to base rates because it is needed to continue to support and perform budget analysis, regulatory reporting, and contract administration tasks for the DSM programs that remain with the utility[1] after the energy efficiency programs are transferred to the PBF Administrator. The CEP Analyst must also consolidate the CEP Division budget, perform budget analysis, validate invoices for payment[2], write portions of the annual DSM program Accomplishments and Surcharge ("A&S") and Modifications and

[1] The programs that remain with the utility after the transfer of the energy efficiency programs to the third-party administrator include the Commercial and Industrial Direct Load Control ("CIDLC"); Residential Direct Load Control ("RDLC"), and SolarSaver Pilot ("SSP") Programs (until July 1, 2010, but current SSP Program participants will need to be tracked through at least 2021).

[2] The CEP Analyst validates every invoice that is charged to the load management programs, e.g., Honeywell for support and implementation of the SBDLC program; Cannon Technologies for the Yukon system; Sprint Wireless, Time Warner telecom, and MetroCall for telecommunication and backup services; MPW Direct for advertising services, Altres for temporary hires, Energy Analytics for data logging services, TYC Consultants for tracking services, and supplies and material purchases.

Evaluation ("M&E") Reports, and administer contracts.[3]

These efforts are to some extent fixed and are not dependent on the presence of energy efficiency programs. While the majority of this work was directed towards the energy efficiency programs while they were being administered by HECO, these functions must continue to be performed by the Company after the transition of the energy efficiency DSM programs to support the load management programs. In addition, since additional demand response programs are being proposed, such as the Dynamic Pricing Pilot Program, the Small Business Direct Load Control program element, and CIDLC load aggregation, it is more than likely that regulatory, budget and contract administration efforts will increase and backfill any work reductions resulting from the transfer of energy efficiency programs.

Q. Please explain the workload increases that require the addition of two SRAs.

A. The first SRA was added as the result of the Company's renewed focus on rate initiatives and customer rate options to assist customers with managing their electric bills as fuel prices rise.

Rate options that price electricity based on cost differences to provide electrical service during different periods are likely to price electricity higher during peak demand periods than for other daily periods. Implementing these rate options provides customers with an opportunity to reduce their electricity bills if they are able to shift usage from the higher cost peak demand periods to lower cost off-peak periods. This has taken on much greater importance due to significant oil price changes and volatility since the summer of 2008. By reducing load during peak demand periods, these rate options also help the Company maintain its service reliability during reserve capacity shortfall situation.

[3] The CEP Analyst also administers outside services contracts and purchase orders associated with the load management programs, e.g., Honeywell (same as above).

The SRA is involved in the design of aggressive time-of-use ("TOU") rate, inclined block rates, and dynamic pricing that are examples of rate options that have been proposed in filings with the Commission in this rate case and in other filings.[4] It is also expected that this SRA will work on a green pricing arrangement once a federal law is passed that clarifies national policy on the economic treatment of green house gas emissions. This position was filled on October 2008.

The second SRA was added to respond to the numerous rate initiatives resulting from the Energy Agreement that cannot be addressed by the existing staff or by the first SRA due to the volume of work required. In the Energy Agreement, HECO committed to a number of new initiatives such as revenue decoupling, lifeline rates, a PV Host Program, and feed-in tariffs. The SRA participated in developing the concepts, design, and implementation guidelines that are included in applications for the Commission's review.[5] (The Rate Case Update, HECO T-10, pages 4-7 includes a list of additional programs and initiatives that were included in the Energy Agreement that also necessitate the participation of the SRA.) This position was filled on February 2009.

Many of these rate initiatives also have timelines, which means that the existing staff is limited in its ability to postpone work on some initiatives in order to complete others. Thus, the new Senior Rate Analyst position is directly related to the requirements of the Energy Agreement.

Q. What are the workload requirements associated with the increase in the VP-

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[4] Two-period TOU rates have been proposed in this docket and are discussed in Exhibit HECO-106, pages 78 to 80 (Schedule TOU-R), and in the AMI docket (Docket No. 2008-0303). The Dynamic Pricing Pilot Program application was filed in April 2008 (Docket No. 2008-0074), and work to respond to the Commission's *Order Directing HECO to Modify its Dynamic Pricing Pilot Program*, dated June 5, 2009, is on-going.

[5] Revenue decoupling (Docket No. 2008-0274), Feed-in Tariff (Docket No. 2008-0273), PV Host Pilot Program (Docket No. 2009-0098, and Lifeline Rate (Docket No. 2009-0096).

Customer Solutions office?

A. The Director, Special Projects, a new regular employee position reporting to the VP-Customer Solutions, is responsible for developing the overall strategy to guide the Company's demand response strategy among the different areas of the Company (see Rate Case Update, HECO T-10, pages 1-4). The work is closely associated with the Energy Agreement. This position was filled in November 2008.

The requirements and the deadlines included in the Energy Agreement increase the scope, intensity, and complexity of work related to demand response as compared to work identified prior to the agreement. The Energy Agreement requires the utilities to explore the use of demand response as a mechanism to accommodate more renewable energy and to manage frequency fluctuations resulting from intermittent renewable resources connected to the grid, and provide a recommendation for such use to the Commission by December 31, 2009. The Energy Agreement also requires the utilities to allow demand response to provide a variety of ancillary services and encourage those demand-side ancillary services if they can be provided more precisely than supply-side resources.[6]

This position was heavily relied upon this year to develop the CIDLC and RDLC Program renewal applications, filed with the Commission on March 31, 2009 and April 30, 2009, respectively. The Director's role was to ensure that the resources acquired through the proposed programs met the needs of the system with regards to the likely future integration of increased amounts of intermittent renewable generation, and further, that the resources would be available when and within the response time required by the Company's system operators. An action plan to address adding more renewable energy and to manage frequency

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[6] Energy Agreement, Section 13, pages 23-24.

fluctuations resulting from intermittent renewable resources connected to the grid was included in the CIDLC Program renewal application.

The position is also required to integrate the demand response programs with efforts in other parts of the Company to implement Advanced Metering Infrastructure and Smart Grid technologies. The ability of the demand response programs and their associated hardware, software, and communications technologies, to interface with these other projects and initiatives is critical to program success. Furthermore, along with the SRA, the Director, Special Projects is also supporting the Company's Dynamic Pricing Pilot Program and its response to the Commission's order.

Q. What is the origin of the increase of one position in the Marketing Services Division and what are the workload requirements associated with the position?

A. Due to settlement discussions with the other parties to the HECO 2007 test year rate case, the Marketing Services Division 2007 test year head count was reduced by one due to a staff vacancy during the test year. Therefore, the increase of one position is not a new position, but instead represents an increase based on filling the position that had been vacant in 2007.

The account managers form a single point of contact for major commercial customers, primarily in Schedules PP, PS, and PT, representing a current total of over 5,084 accounts. Major customer services also include communication during power outages, rate analyses, meter and billing consolidation analyses, power factor payback calculations, and coordination of service connections and related services. The Division provides energy solutions assessments and recommendations for major customers; sponsors and conducts conferences, seminars, workshops, trade shows; conducts power quality assessments and recommendations; and assists major customers with electro-technologies applications. This position was filled in April 2009.

Q. Are there any position vacancies in the Customer Solutions Process Area as of June 30, 2009?

A. Yes, there were two vacancies as of June 30, 2009 both of which were in ESD. The first vacancy is the CEP Analyst in the CEP Division, which the Company proposes to transfer from incremental to base rate recovery (see above). This position is currently filled. Based on the Commission's July 2, 2009 ID&O in this docket, which includes recovery of this position through base rates, this position would be switched from incremental to base rate recovery on the effective date of the interim rate increase (when approved by the Commission) and be added to the ESD headcount.

The June 30, 2009 second vacancy is a Rate Analyst in the Pricing Division. The position offer letter was signed and accepted by the incoming Rate Analyst on July 10, 2009 and will start August 3, 2009. Therefore, that position is no longer vacant.

Therefore, upon approval of by the Commission of the Interim Rate Increase and the start of employment in the Pricing Division by the new Rate Analyst on August 3, 2009, the Customer Solutions Process Area will not have any unfilled positions.

Q. Please describe the changes in organization and June 30, 2009 actual staffing that occurred as the result of the March 2009 Company reorganization.

A. The March 2009 Company reorganization split the VP-Customer Solutions Process Area into various parts. The Energy Services Department remained intact (14 staff), but added the Research portion of the Forecasts & Research Division (six staff). The Director, Special Projects, was also added to ESD. ESD exited from the reorganization under the Executive VP, Clean Energy, with June 30, 2009 actual staffing of 21.

The Forecast portion of the Forecasts & Research Division (four staff) was transferred to the Corporate Planning Department. The VP-Customer Solutions Office became the VP-Customer Service with two staff because the Director, Special Projects that had been attached prior to the reorganization was incorporated in the ESD (see above).

The Customer Technology Applications Division (nine staff) and Marketing Services Division (12 staff) were combined to create the Energy Solutions Department.

Q. Please summarize the Company's proposed test year VP-Customer Solutions Process Area headcount, prior to the reorganization.

A. The VP-Customer Solutions Process Area headcount is 50, representing an increase of five over the 2007 test year average (excluding the six incremental DSM positions removed from the 2007 test year average in the September 5, 2007 settlement agreement). The increased staffing results from an increase in workload over the 2007 test year, primarily due to the focus on rate options that will provide ways for customers to manage their electricity bills and facilitate the addition of more renewable energy resources on the Company's system, increased workload associated with new initiatives related to the DSM programs that HECO continues to administer, and efforts to provide basic account management services to the Company's major customers. The increase is unrelated to the DSM energy efficiency programs that were transferred to the third-party administrator because all of the supported increase in work requirements results from the Company's focus on its retained DSM programs, demand response, and efforts to better serve its customers.

BASE DSM EXPENSES

Q. How do base DSM expenses compare with previous years?

A. A comparison of base DSM expenses with prior years is shown on Exhibit HECO-S-1003. The 2009 test year base DSM expenses at direct testimony totaled to $2,374,000. This amount was reduced to $2,029,000 after the rate case update and settlement discussion with the Consumer Advocate. The settlement amount of $2,029,000 is approximately $337,000 higher than the average of the previous three years' recorded amounts from 2006 to 2008[7], and is $363,000 higher than 2008's recorded figure. Exhibit HECO-S-1003 superimposes 2009 test year estimates from direct testimony, changes from the rate case update and May 15, 2009 HECO test year 2009 rate case settlement agreement ("Settlement Agreement") with the Consumer Advocate onto the Company's response to CA-IR-410, page 3, which originally only showed the historical trend of base DSM expenses from 2005 to 2008. The superimposed portion is shaded for ease of identification.

Q. What is the impact on Customer Service expenses with the transfer of energy efficiency ("EE") programs to the public benefits fund ("PBF") Administrator?

A. HECO's estimate of the 2009 test year Customer Service expenses of $5,784,000 in its settlement position (Settlement Agreement, Exhibit 1 at 46) does not include expenses for EE DSM programs. Those expenses were removed from the test year estimate or were already excluded from the test year estimate because they were being recovered through the DSM surcharge as incremental costs. Also, as shown on HECO-S-1000, labor and non-labor expenses for the following eight EE programs were removed from the 2009 test year: (1) Commercial & Industrial

[7] $2,029,000 – ($1,713,000 + $1,698,000 + $1,666,000)/3 years) = $337,000

Energy Efficiency ("CIEE"), (2) Commercial & Industrial New Construction ("CINC"), (3) Commercial & Industrial New Construction ("CINC"), (4) Residential Efficient Water Heating ("REWH"), (5) Residential New Construction ("RNC"), (6) Energy Solutions for the Home ("ESH"), (7) Residential Low Income ("RLI"), and (8) Residential Customer Energy Awareness ("RCEA").

Q. With the removal of EE programs given the transfer of these programs to the PBF Administrator, what caused the increases in base DSM expenses comparing to prior years?

A. The increase in the test year base DSM expenses from prior years is due primarily to increases in expense for the two load management programs that remain with HECO following the transfer of the energy efficiency programs to the PBF Administrator. These two load management programs are the Commercial & Industrial Load Control ("CIDLC") and Residential Direct Load Control ("RDLC"). Generally speaking, these increases are related to (1) the effort related to marketing the CIDLC program to customers with smaller potential load reduction potential, (2) the implementation of the full-scale rollout of the Small Business Direct Load Control ("SBDLC") program element as part of the CIDLC Program, (3) the cost to conduct a comprehensive CIDLC program evaluation, (4) the challenges that a more saturated market is expected to pose for increasing participation in the RDLC program, (5) the cost to conduct a comprehensive RDLC program evaluation, (6) increase in advertising expense for the RDLC program, (7) reallocation of labor hours and vacancies for portions of 2008, and (8) increase in DSM-related administration labor expense.

Q. How does marketing the CIDLC program to customers with smaller potential load increase base labor expense?

A. As discussed in HECO T-10, page 27, after nearly four years of program implementation, the opportunities to enroll large individual demand reductions from large customers are fewer. The trend in the size of enrolled customer loads can be seen in HECO's response to CA-IR-414, Attachment 1, page 6 of 6. The average size of the enrolled load in 2008 was 294 kw, compared to the average size of enrolled loads in 2005, 2006 and 2007, of 967 kw, 479 kw, and 802 kw, respectively. Therefore, to attain the same MW level of demand reductions equivalent to a large customer, many smaller customers may have to be enrolled. This increases the labor time, resources, and cost necessary to enroll similar levels of demand reduction.

Second, recent modifications to the CIDLC program approved by the Commission reduce the minimum load size eligible to participate in the program. This increases the number of potential program enrollees, but also means that with smaller loads, the number of participants necessary to attain program goals will be higher than in prior years and a greater number of on-site facility assessments, marketing visits, and in-house engineering studies will be needed to attain those goals. The increased level of activity is expected to increase program labor expenses.

Q. How do vacancies in 2008 contribute to the increase in base CIDLC labor expense?

A. The increase in test year CIDLC Program labor expense over 2008 actual expenses is that both the CIDLC Program Manager and Load Management Engineer positions were vacant for portions of 2008 (see HECO's response to CA-IR-338, Attachment 1). The test year program labor assumes that both positions are filled for the entire year. Therefore, the test year labor estimate is expected to be higher than the 2008 expense.

Q. How does implementing the SBDLC element of the CIDLC program increase cost?

A. As stated in the Company's response to CA-IR-119, page 4, "While offering load control options to small businesses via the SBDLC program element increases the amount of controllable load, it tends to be more costly on a per incremental curtailable kW basis than the large commercial and industrial programs. The reason for this is, unlike the residential sector, the small business sector is heterogeneous, i.e., there are many different businesses types with different end-uses. Therefore, direct mailing followed up by one-on-one customer sales is required to attain participation in the program. Thus, program cost per participant or per curtailable kW is relatively high."

In the Company's response to CA-IR-409, page 5, HECO stated "This program is targeted to small commercial customers and thus relies on direct mailing and direct sales efforts to attract new participants, resulting in higher advertising/marketing costs. In the Company's four-month pilot program, it was confirmed that: 1) direct mail efforts provided some initial sales leads, 2) canvassing commercial and industrial areas provides better leads, and 3) a one-step sales process with SBDLC is very difficult. All these results confirm that it is much more costly to advertise/market the SBDLC program element than the rest of the CIDLC program."

HECO's test year estimate of non-labor costs associated with the third party SBDLC program of $403,656 is shown in HECO-1019. In the Settlement Agreement, HECO and the Consumer Advocate agreed that the estimated test year third-party advertising/marketing and materials & miscellaneous expense of $322,920 should be reduced by 50% to reflect the implementation of the program in the second half of 2009, resulting in an adjusted test year non-labor estimate for advertising/marketing and materials & miscellaneous expenses of $156,000.[8]

Earlier this year, HECO sent out invitations to six companies who were deemed qualified to bid on the SBDLC program. Three companies requested the RFP, but only one company actually responded with a proposal, which was received on June 8, 2009. We are currently reviewing that proposal to determine the extent to which it meets HECO's program budget and objectives.

Q. How does conducting a comprehensive CIDLC program evaluation increase cost?

A. Tracking and evaluation efforts during the test year are expected to increase base DSM expense by $59,000. As discussed in HECO's response to CA-IR-414, page 2, participation in the first two years of the program, measured by number of enrolled customers, was too low to conduct a meaningful evaluation of the program. In addition, HECO has near-real-time telemetry of the CIDLC customers' curtailable load, making a full evaluation of the program less important. However, after four years of implementation and the addition of two new program elements (Voluntary Load Control and SBDLC), HECO maintains that it is necessary to conduct a more formal structured evaluation. The test year expense for tracking and evaluation reflects a two-year amortization since the evaluation is expected to be conducted only once before HECO's next rate case (see the Settlement Agreement, Exhibit 1 at 44).

Q. How does continued penetration of residential customers in the RDLC program increase cost?

A. The increase in RDLC program expenses of $294,000 compared to 2008 actual expenses is in both labor and non-labor expenses, as shown in HECO-S-1000. The increase in labor expense is $77,000, and non-labor expense is $217,000.

As described in HECO's response to CA-IR-415, while HECO was

[8] Test year third-party vendor tracking and evaluation costs were reduced in the Settlement Agreement by amortizing those costs over two years. See the discussion later in this testimony.

administering the energy efficiency DSM programs, the RDLC Program Manager devoted a substantial portion of her time to the REWH and RNC programs, which meant that the Program Manager had to split her time with other programs. With the transfer of the REWH and RNC programs to the PBF Administrator, the RDLC Program Manager can now focus more of her time on the RDLC program that is necessary to administer the growing central air conditioning portion of the program and oversee new efforts to add load control of split system air-conditioners to the portfolio of end use measures. The increase in labor hours spent on the RDLC Program will facilitate the inclusion of the quickly growing split air conditioning market into HECO's load management programs. The increase in labor hours also reflects the partial vacancy in this position that spanned 2007 and 2008 (see response to CA-IR-228, Attachment 1).

The increase in RDLC Program non-labor expense is $217,000. The increase in non-labor overheads is associated with the increase in labor expenses. A comprehensive program evaluation discussed below also adds $55,000 to the cost increase.

Q. How does conducting a comprehensive RDLC program evaluation increase cost?

A. As discussed in HECO's response to CA-IR-415, the increase in tracking/evaluation expenses is due to an evaluation of the program in 2009. Very little evaluation work was done in the previous years of the program. However, after four years of tracking the program results through annual testing of the program, HECO maintains that it is necessary to conduct a more rigorous evaluation. The increase in program tracking/evaluation expense of $55,000 above 2008 actual expenses has already been amortized over two years since the evaluation is expected to be conducted only once before the next HECO rate case (Settlement Agreement, Exhibit 1 at 44).

Q. How does advertising expense for the RDLC program for test year 2009 compare with prior years?

A. The increase in RDLC Program advertising expense of $126,000 above 2008 actual expenses[9] reflects the expectation that as participation in the water heating portion of the program approaches market saturation more closely, efforts to market the program will become more expensive As discussed in CA-IR-415, early adopters have already enrolled in the program and almost all eligible residential customers have seen the direct mail offers to join the program multiple times since the program was implemented in 2005. Therefore, efforts to encourage the remaining customers to enroll will necessarily involve greater efforts to increase program awareness and identify participant and community benefits of the program. This greater effort is expected to increase advertising expenses.

Q. How do vacancies and reallocation of labor hours increase 2009 test year base DSM labor expense above actual 2008 expenses?

A. As discussed above, the CIDLC Program Manager and Loan Management Engineer, and the RDLC Program Manager positions were vacant for portions of 2008. This resulted in recorded 2008 labor expenses being lower than if these three positions were occupied for the entire year, as is assumed during the 2009 test year.

Furthermore, while HECO administered the EE programs, the RDLC Program Manager also assisted with management of the REWH and RNC programs (see response to CA-IR-228, Attachment 1). With the transition of EE programs to the PBF Administrator, and as the number of households participating in the electric resistance water heaters portion of the RDLC Program

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[9] See HECO's response to CA-IR-412, Attachment 1, pages 2 and 3: estimated 2009 test year advertising expense of $424,000 less actual 2008 RDLC advertising expense of $298,000 = $126,000.

approach saturation, the RDLC Program Manager is expected to increase focus on the program to target households with central air-conditioners, and evaluate addition of new measures, such as split air-conditioning systems. The RDLC Program Manager will also oversee the DPP and other initiatives resulting from the Energy Agreement (see HECO response to CA-IR-228, page 2). The vacant months in 2008 and re-allocation of the RDLC Program Manager time contributed to the increase in 2009 test year increase in RDLC labor expense. The CIDLC Program Manager, CIDLC Load Management Engineer, and RDLC Program Manager positions were fully staffed from January 2009.

Q. What are the reasons for the increase in DSM-related administration labor expense?

A. DSM-related administration labor expense increase by $34,000 over 2008 recorded expense. As discussed in the Company's response to CA-IR-232, page 2, DSM-related labor expense represents overall administration costs of the DSM programs that are not associated with specific DSM programs. These efforts include developing policy, researching and tracking national DSM trends, developing action plans, goal setting and tracking, management and regulatory reporting, budgeting, contract administration, personnel administration, overall utility DSM program marketing through customer contact, and secretarial and clerical duties.

These efforts are still required for administration of the programs that remain with the utility, i.e., the two load management programs, the SolarSaver Program, and the Dynamic Pricing Pilot Program. Thus, unlike DSM program expenses, these DSM-related efforts are primarily fixed and are not expected to change when the energy efficiency programs are transferred to the PBF Administrator.

However, the test year estimate of DSM-related labor expense also includes efforts to develop, plan, and design new demand response programs that reduce demand and maintain service reliability (see HECO T-10, page 21, lines 4 to 19). Therefore, the increase in DSM-related administration expense is due to additional effort to research and develop conceptual designs for demand response programs that can address frequency fluctuations resulting from intermittent renewable energy sources, which is a major focus of the Energy Agreement. Furthermore, with the transition of the energy efficiency programs to the PBF Administrator, there will be new DSM-related administrative activities to interact and coordinate program, reporting, and statistical requirements with the PBF Administrator.

SUMMARY

Q. Please summarize your supplemental testimony.

A. In summary, for the Customer Solutions headcount, the VP-Customer Solutions Process Area headcount is 50, representing an increase of five over the 2007 test year average (excluding the six incremental DSM positions removed from the 2007 test year average in the September 5, 2007 settlement agreement). The increased staffing results from an increase in workload over the 2007 test year, primarily due to the focus on rate options that will provide ways for customers to manage their electricity bills and facilitate the addition of more renewable energy resources on the Company's system, increased workload associated with new initiatives related to the DSM programs that HECO continues to administer, and efforts to provide basic account management services to the Company's major customers. The increase is unrelated to the DSM energy efficiency programs that were transferred to the third-party administrator because all of the supported increase in work requirements results from the Company's focus on its retained DSM programs, demand response, and efforts to better serve its customers.

As to the increase in base DSM expenses, this is due to (1) the effort related to marketing the CIDLC program to customers with smaller potential load reduction potential, (2) the implementation of the full-scale rollout of the Small Business Direct Load Control (SBDLC) program element as part of the CIDLC Program, (3) the cost to conduct a comprehensive CIDLC program evaluation, (4) the challenges that a more saturated market is expected to pose for increasing participation in the RDLC program, (5) the cost to conduct a comprehensive RDLC program evaluation, and (6) increase in advertising expense for the RDLC program. These increases, together with the offsetting decreases, are summarized in Exhibit HECO-S-1000, variance versus 2008 columns, by labor and non-labor categories.

Q. Does this conclude your supplemental testimony?

A. Yes, it does.

Customer Solutions Process Area Employee Headcount Comparison Without Re-Organization

(Increased to Include Positions Removed from Base Rates in the 2007 TY Rate Case Settlement Agreement)

CONSISTENT HISTORICAL COMPARISON	Sett 2007 Test Year Average	Updated 2009 Test Year Average	Difference 2009 Upd Ave - 2007 Test Year Ave	6/30/09 Actual Count
VP-Customer Solutions				
Customer Technology Applications	9	9	0	9
Energy Services	19	16	-3	14
Administration Division	3	3	0	3
Pricing Division	5	7	2	6
Customer Efficiency Programs Division*	11	6	-5	5
Forecasts & Research	10	10	0	10
Marketing Services	11	12	1	12
VP-Customer Solutions' Office	2	3	1	3
Subtotal	51	50	-1	48

* Includes 6 positions that were removed from base rates in the September 5, 2007 Settlement Agreement filed with the PUC.

Customer Solutions Process Area Employee Headcount Comparison Without Re-Organization

(Decreased to Exclude Positions Removed from Base Rates in the 2007 TY Rate Case Settlement Agreement)

CONSISTENT HISTORICAL COMPARISON	Sett 2007 Test Year Average	Updated 2009 Test Year Average	Difference 2009 Upd Ave - 2007 Test Year Ave	6/30/09 Actual Count
VP-Customer Solutions				
Customer Technology Applications	9	9	0	9
Energy Services	13	16	3	14
Administration Division	3	3	0	3
Pricing Division	5	7	2	6
Customer Efficiency Programs Division**	5	6	1	5
Forecasts & Research	10	10	0	10
Marketing Services	11	12	1	12
VP-Customer Solutions' Office	2	3	1	3
Subtotal	45	50	5	48

** Does not Include 6 positions that were removed from base rates in the September 5, 2007 Settlement Agreement filed with the PUC.

Customer Solutions Process Area Employee Headcount Comparison With Re-Organization

COUNTS REALLOCATED TO NEW ORGANIZATION (3/2/09 REORG AND SUBSEQUENT)	(Adjusted) Settlement 2007 Test Year Average	(Adjusted) 2009 Update Test Year Average	Difference 2009 Upd Ave - 2007 Test Year Ave	6/30/09 Actual Staffing
VP-Customer Service (formerly VP Cust. Solutions)				
VP-Customer Service Office	2	2	0	2
Subtotal	2	2	0	2
Exec. VP, Clean Energy (formerly EVP-Public Affairs)				
Energy Services received from VP-Cust Sols eff 3/2/09	25	23	-2	21
Energy Solutions (new dept eff 3/2/09)	20	21	1	23
Subtotal	45	44	-1	44
Total	47	46	-1	46

Employee counts were adjusted as if the new organization was in place at the time of the 2007 rate case settlement and the 2009 rate case update.

Hawaiian Electric Company, Inc.

DSM EXPENSES
Actual Base DSM Expenses vs. 2009 O&M Expense Budget

($1,000s)

Line		2005 Actuals		2006 Actuals		2007 Actuals		2008 Actuals		2009 TY Dir Testimony		T-10 RC Update pps 9, 16, 17		Settlmnt, Exh 1 pps 43, 44		Settlmnt Position		Variance Versus 2008	
		Labor	Non-Labor	Labor	Non-Labor	Labor	Non-Labor	Labor	Non-Labor	Labor	Non-Labor	Labor	Non-Labor	Labor	Non-Labor	Labor	Non-Labor	Labor	Non-Labor
1	DSM Base Program Costs																		
2	CIEE	84	22	100	64	75	46	14	9	0	0 (a)					0	0	(14)	(9)
3	CINC	44	16	59	26	49	25	8	5	0	0 (a)					0	0	(8)	(5)
4	CICR	42	16	52	24	42	22	10	6	0	0 (a)					0	0	(10)	(6)
5	REWH	52	18	47	20	21	10	25	11	0	0 (a)					0	0	(25)	(11)
6	RNC	19	7	28	12	14	7	16	7	0	0 (a)					0	0	(16)	(7)
7	ESH	0	0	17	8	27	13	3	1	0	0 (a)					0	0	(3)	(1)
8	RLI	0	0	0	0	17	8	0	0	0	0 (a)					0	0	0	0
9	RCEA	0	0	0	0	3	1	4	2	0	0 (a)					0	0	(4)	(2)
10	CIDLC	169	87	241	147	162	152	145	377	212	677 (a)				(226) (e)	212	451	67	74
11	RDLC	71	182	40	306	25	390	16	319	75	583 (a)	18	8 (d)		(55) (f)	93	536	77	217
12	SSP	0	0	0	0	12	6	37	19	27	12 (a)(b)	(18)	(8) (d)			9	4	(28)	(15)
13	DDP	0	0	0	0	0	0	0	0	15	8 (a)(b)					15	8	15	8
14	Total Program Costs	481	348	584	607	447	680	278	756	329	1,280 (a)	0	0	0	(281)	329	999	51	243
15	DSM-Related Expenses																		
16	Administration	187	85	209	139	260	126	296	145	374	172 (c)			(44)	(20) (g)	330	152	34	7
17	ITS	0	250	0	174	0	185	0	191	0	219 (c)					-	219	0	28
18	Total DSM-Related Expenses	187	335	209	313	260	311	296	336	374	391 (c)	0	0	(44)	(20)	330	371	34	35
19	**Total Base DSM Expenses**																		
20	**All NARUC Accounts**	**668**	**683**	**793**	**920**	**707**	**991**	**574**	**1,092**	**703**	**1,671 (c)**	**0**	**0**	**(44)**	**(301)**	**659**	**1,370**	**85**	**278**
21	**Total Base DSM Labor and Non-Labor**		**1,351**		**1,713**		**1,698**		**1,666**		**2,374**		**0**		**(345)**		**2,029**		**363**

Reference:
(a) HECO-1015 (SSP and DPP Program expense estimates include "Other Than Account 910" program costs)
(b) HECO-1014
(c) HECO-1013
(d) Reallocate 452 hours from SSP Program to RDLC Program (HECO T-10 Rate Case Update at 9 and 16)
(e) Amortize $118,000 of CIDLC evaluation cost over two years and reduce $322,920 of SBDLC advertising/marketing and materials/miscellaneous expense by 50% (Settlement Exhibit 1 at 44)
(f) Amortize $111,000 of RDLC evaluation cost over two years (Settlement Exhibit 1 at 44)
(g) Settlement agreement with Consumer Advocate to reduce base DSM-related administration expense due to transfer of EE programs to PBF Administrator (Settlement Exhibit 1 at 44)
Labor and non-labor adjustment uses the split of $546,000 of non-ITS labor and non-labor expenses shown in HECO-1013 (68.5%/34.5%).

HECO ST-10B
DOCKET NO. 2008-0083

SUPPLEMENTAL TESTIMONY OF

JEFF D. MAKHOLM, PH.D

On Behalf of
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Energy Cost Adjustment Clause

SECTION I: INTRODUCTION

Q. Please state your name, business address and current position.

A. My name is Jeff D. Makholm. I am a Senior Vice President at National Economic Research Associates, Inc. ("NERA"). NERA is a firm of consulting economists with its principal offices in a number of major U.S. and European cities. My business address is 200 Clarendon Street, Boston, Massachusetts, 02116.

Q. Please describe your academic background.

A. I have M.A. and Ph.D degrees in economics from the University of Wisconsin, Madison, with a major field of industrial organization and a minor field of econometrics/public economics. My 1986 Ph.D dissertation is entitled "Sources of Total Factor Productivity in the Electric Utility Industry." I also have B.A. and M.A. degrees in economics from the University of Wisconsin, Milwaukee. Prior to my latest full-time consulting activities, I was an adjunct professor in the Graduate School of Business at Northeastern University in Boston, Massachusetts, teaching courses in microeconomic theory and managerial economics.

Q. Please describe your work experience pertinent to this proceeding.

A. My work centers on economic issues involving pricing, regulation and market issues for regulated infrastructure industries, including gas, electricity, water and telecommunications utilities, gas and oil pipelines, airports, toll roads and passenger and freight railroads. My consulting work includes the specific issues of competition, rate design, fair rate of return, regulatory rulemaking, incentive ratemaking, load forecasting, least-cost planning, cost measurement, contract obligations and bankruptcy. I have prepared expert testimony and statements, and I have appeared as an expert witness in many state and federal administrative and United States District Court proceedings, as well as in regulatory and judicial hearings abroad.

I have also directed studies on behalf of utility companies, governments and the World Bank in many countries. In these countries, I have drafted regulations, established tariffs, recommended financing options for major capital projects and advised on industry restructurings. I have also assisted in the privatization of state-owned gas utilities. As part of my international work, I have conducted formal training sessions for government, industry and regulatory personnel on the subjects of privatization, pricing, finance and regulation of the gas industry.

Over the past 25 years, I have presented evidence on many ratemaking subjects, including the pass-through of fuel, purchased energy and gas costs. For example, in 2005, I prepared testimony on the role of fuel adjustment clauses ("FACs") and related financial issues for Portland General Electric as well as a report summarizing the current state of FACs in the United States. I have testified on numerous occasions recently on behalf of Sierra Pacific Power Company and Nevada Power Company with respect to their natural gas hedging programs and related cost recovery. Overall, I have testified for electric, natural gas, water and telecommunications clients before the Federal Energy Regulatory

Commission (the "FERC"), the Federal Communication Commission (the "FCC") and state commissions in Pennsylvania, Oregon, Ohio, North Carolina, Kansas, Illinois, New Jersey, New York, Maryland, California, Virginia, Rhode Island, New Hampshire, Texas, Indiana, Maine, Nevada, Wisconsin, Georgia and Connecticut.

My current curriculum vitae, which more fully details my educational and consulting experience, is provided as Exhibit HECO-S-10B00.

Q. Did you previously submit testimony is this proceeding?

A. No, I did not.

Q. Did you previously submit testimony in other proceedings before the Hawaii Public Utilities Commission?

A. Yes, I did. I sponsored direct testimony HECO T-21 on energy cost adjustment clause ("ECAC") in the Company's 2005 test year rate case, Docket No. 2006-0386.

Q. What is the purpose of your testimony in this proceeding?

A. In the Commission's Interim Decision and Order filed July 2, 2009 in this instant docket, the Commission indicated it desires additional testimony regarding whether Hawaiian Electric Company, Inc.'s ("Hawaiian Electric" or "HECO") proposed ECAC complies with the statutory requirements of HRS § 269-16(g) (Interim Decision and Order at 14 to15). I have been asked by Hawaiian Electric to provide testimony explaining the role of fuel adjustment clauses in utility ratemaking in the United States. I address the compliance of HECO's current power cost recovery mechanism, the ECAC, with the applicable statute.[1] I discuss and assess the potential impacts of fuel price hedging on HECO, its customers, and the regulatory ratemaking process. I explain that FACs are an important element in maintaining a vital and financially secure electric utility system that provides efficient, safe, adequate and reliable service—the benefits of which flow to customers over time.

Q. How is your testimony organized?

A. In Section II, I evaluate HECO's ECAC in terms of the five specific requirements established by Act 162. In Section III, I discuss the historical context of and the economic and ratemaking rationale behind FACs and provide a brief description of the current status of power cost recovery in the United States, focusing mainly on traditionally-regulated (as opposed to restructured) states.

SECTION II: ECAC'S COMPLIANCE WITH ACT 162

Q. Please describe the requirements for automatic fuel rate adjustment clauses outlined in Act 162.

[1] A Bill for an Act Relating to Energy, S.B. No. 3185, S.D. 2, H.D. 2, C.D. 1, Act No. 162, Approved by the Governor of Hawaii on June 2, 2006 (Herein after, "Act 162") amended Section 269-16 of the Hawaii Revised Statutes to include a subsection (g) that outlines requirements for the design of "any automatic fuel rate adjustment clause," of which the ECAC is one.

A. Act 162 incorporates five requirements for the design of any public utility automatic rate adjustment. Act 162 requires that any automatic rate adjustment be designed to:

1. Fairly share the risk of fuel cost changes between the public utility and its customers;

2. Provide the public utility with sufficient incentive to reasonably manage or lower its fuel costs and encourage greater use of renewable energy;

3. Allow the public utility to mitigate the risk of sudden or frequent fuel cost changes that cannot otherwise reasonably be mitigated through other commercially available means, such as fuel hedging contracts;

4. Preserve, to the extent reasonably possible, the public utility's financial integrity;

5. Minimize, to the extent possible, the public utility's need to apply for frequent applications for general rate increases to account for the changes to its fuel costs.[2]

Q. Have you examined HECO's current FAC mechanism, the ECAC?

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[2] Section 269-16(g) of the Hawaii Revised Statutes as revised by Act 162, pp. 17-18.

A. Yes, I have.

Q. What did you find?

A. The ECAC includes fuel, purchased energy, and distributed energy costs. It computes the monthly weighted average of the various fuel, purchased energy and distributed energy costs based on fuel mix, which is then converted to a rate for customers based on the estimated MWh sales for the month. The ECAC uses an efficiency factor (measured in MBtu/kWh) to calculate the conversion between the MBtu of fuel purchased and the amount of kWhs generated.[3] The ECAC contains a quarterly reconciliation for the previous quarter's actual experienced fuel and purchased energy expenses on a per-kWh basis relative to the forecasted amounts. This reconciliation ensures the timely recovery of fuel and purchased energy costs for HECO or timely refund/credit to the ratepayers.

Q. How would you compare HECO's ECAC to the power cost recovery practices of the rest of the United States?

A. The ECAC compares well to the FACs that are used in traditionally-regulated jurisdictions in the U.S. Nearly all traditionally regulated and most restructured states have some similar mechanism for power cost recovery with complete fuel cost recovery.

Q. What are your conclusions?

[3] It is my understanding that this may change to a heat rate "deadband" approach as jointly proposed by the Hawaiian Electric Companies (HECO, Hawaii Electric Light Company, Inc., and Maui Electric Company, Ltd.) and the Consumer Advocate in the decoupling proceeding, Docket No. 2008-0274).

A. I conclude the following:

- HECO's ECAC complies with the statutory requirements of Act 162.
- HECO's ECAC is a well-designed FAC and benefits HECO and its ratepayers.
- FACs are a standard and longstanding part of US utility ratemaking.

I now consider the ECAC's compliance with each of these requirements.

A. Fair Risk Sharing of Fuel Cost Changes

Q. What is the "risk of fuel cost changes?"

A. The risk of fuel cost changes comprises two things:

- Changes in the *price* of fuel as a single productive input; and,
- Changes in the *cost* to deliver and produce electricity from HECO's fuel inputs. This reflects any changes in the technical ability of the utility to turn purchased fuel into electricity, which may require HECO to purchase a greater *quantity* of fuel, and thus increase the overall level of fuel costs, in order to produce the same amount of electricity.

Q. How should the risk of changes in the *price* of fuel as a productive input be "fairly shared?"

A. Fair risk sharing occurs when the utility has the means to control a cost and it has a corresponding incentive to do so (*i.e.*, it shares the risk associated with that cost). It is not economically efficient to impose risk of cost recovery on the utility when the utility is not able to control the cost. This distinction is critical because the *price* of fuel is, realistically, beyond the control of the utility. HECO acts as a price taker in the world-wide market for fuel (oil) and the design of the ECAC and the recovery of fuel and purchased energy costs should recognize this fact.

Under the ECAC, exogenous changes in fuel *input* costs are passed fully onto consumers. In fuel markets (as in other markets where HECO is a price taker – service vehicles, for example), it is straightforward to demonstrate prudent purchasing. There is a well-defined market price and a well-defined need to buy from this market (*i.e.*, ratepayers' demand for electricity). In a price-taking market, imposing price change risks on the utility would lead to no efficiency gains resulting from management incentives to minimize costs. Passing such erogenous costs through supports the utility's ability to maintain its financial viability, and it would increase regulatory lag—the time between rate cases—for costs that *are* within the utility's control, which would enhance the utility's incentive to control its base rate costs.

Q. Please describe the risk of changes in the *cost* to deliver and produce electricity from HECO's fuel inputs.

A. The ECAC, with its "heat rate" efficiency factor (which may change to a heat rate deadband approach as jointly proposed by the Hawaiian Electric Companies and the Consumer Advocate in Docket No. 2008-0274), provides a partial pass-through of fuel costs. It shares the costs and/or benefits of decreased or increased plant operating efficiency by tying HECO's ability to recover its fuel costs (and thus its financial performance) to its power plant performance over which it has some managerial control, while also allowing HECO to pass through the exogenous changes in the price of an input over which it has no control, the price of fuel, purchased energy, and distributed energy.

HECO has considerable control over the operation of its plants—limited by engineering realities—and therefore it is reasonable to provide HECO with an incentive to improve its operating efficiency to manage or lower its fuel costs, as the Commission already does. In contrast, it penalizes HECO if its operating efficiency is subpar.

This heat rate efficiency factor assigns the risk of changes in the cost to deliver and produce electricity from HECO's fuel inputs to HECO's management, while allowing changes in the price of fuel to be passed through to ratepayers.

Q. What are the potential costs associated with improperly assigning fuel cost recovery risk to the utility over which it has no control?

A. Doing so could harm the utility's financial health, its credit rating and its ability to raise capital from the financial markets and would blur the customers' incentive to curb their use of electricity.

If a utility only partially recovers its power costs through its FAC, investors will require a higher return on their capital to reflect the riskier investment.[4] While a partial pass-through of power costs may initially reduce the level of rates when unexpected fuel price increases occur, it may ultimately lead to higher costs to consumers.

From the standpoint of utility customers, a FAC that does not accurately reflect the cost of fuel could affect the customer's incentives to control their use of electricity by not sending the correct price signals.

B. Utility Incentives for Fuel Costs and Renewable Energy

Q. What is the second condition required by Act 162?

A. Act 162 requires that automatic rate adjustment mechanisms be designed to "[p]rovide the public utility with sufficient incentive to reasonably manage or lower its fuel costs and encourage greater use of renewable energy."

This condition is closely tied to the previous one. HECO's targeted efficiency factor promotes productive fuel use decisions and gives HECO an incentive to reasonably manage or lower its fuel costs.

If HECO achieves more efficient plant performance than the level of the efficiency factor (currently set at 0.011140 Mbtu/kWh of sales), then HECO receives a reward. If it fails to meet this target for some reason, then it would

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[4] A utility's cost of equity is set based on a comparable group. Nearly all utilities have cost-recovery mechanisms in place.

not be able to recover the additional purchased fuel expenditures required to produce the kWhs.

Q. Should all purchases of fuel and electricity (renewable and non-renewable) be on an equal footing?

A. Yes. The ECAC should cover all purchased energy costs, including renewable and distributed generation sources, on an equal footing within the cost recovery mechanism. Renewable and distributed energy resources can be part of a utility's power procurement to the extent that they are cost-efficient, reliable and represent a diverse source of generation relative to the traditional non-renewable resources. Like many utilities, HECO creates and follows an Integrated Resource Plan ("IRP"), which determines the extent of renewables and distributed generation used in HECO's fuel mix. The IRP process balances cost-minimization with resource diversity and other concerns.

To ensure the efficient use of renewable resources, the ECAC covers all purchased energy costs, including renewable sources, on an equal footing. Currently, the ECAC is adjusted each month for changes in the energy mix of the sources of fuel and purchased energy. Under an equal footing structure, there is no disincentive from a cost recovery standpoint to purchase renewable energy.[5] It is my understanding that all of the costs that are recovered through

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[5] Purchased capacity costs of renewable resources are not recovered through the ECAC. It is my understanding that purchased energy capacity costs and the operation and maintenance expense component of energy costs are recoverable through rate bases. (SNL Interactive:Hawaii Public Utitlites Commission.

…

the ECAC are variable in nature and that this aspect of the ECAC would not be affected by any effort to introduce "decoupling" in Hawaii.[6]

Q. Could a frequently updated and well designed FAC mechanism support renewable resource development?

A. Yes. The ECAC has positive implications on a utility's financial integrity and can improve a utility's credit ratings, thereby moderating the cost of capital borne by ratepayers.[7] The ECAC allows utilities to recover renewable energy expenses in a timely manner, subject to Commission oversight, without waiting for a rate case. Because the utility may serve as a counter-party for renewable energy developers, the credit standing of a utility frequently serves as an important determinant of renewable energy projects' ability to raise capital, and thus, improve reliability and resource diversity. Weakening the utility's credit rating through partial power cost recovery could harm renewable energy projects that rely on utility counter-party credit to support their investments. Thus, the ECAC is a useful and timely mechanism to accommodating increased amounts of renewable energy.

Q. Act 162 is concerned specifically with the incentive structure facing utilities. Is this the only set of incentives a regulator should consider?

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http://www.snl.com/interactivex/CommissionDetails.aspx?ID=4136041&Type=1&State=HI. Accessed July 19, 2009.

6 The Hawaiian Electric Companies, Consumer Advocate, and other parties are discussing decoupling issues in Docket No. 2008-0274.

7 Since essentially all US electric utilities have a FAC, this is already factored into the comparable group analysis that is used to set the allowed ROE.

A. No. Just as it is proper in the pursuit of economic efficiency for utilities to have incentives to efficiently manage costs over which they have control, incentives are also important for ratepayers, i.e., their economic incentive to use or not use electricity. Ratepayers will not necessarily choose to consume an efficient level of electricity it they are shielded from the true costs of producing electricity, and a timely FAC therefore has an important role to play in transmitting these price signals. When consumers are aware of, and can respond to, the cost effects of their energy consumption decisions, they may reduce their demand when the price outweighs the benefit of consuming the product. Braulio Baez, the Chairman of the Florida Public Service Commission states in a Consumer Bulletin concerning fuel price adjustments:

> The action of removing fuel costs from base rates had the effect of reducing fluctuations in base rates. Both the utilities and their customers now had a better incentive to respond to fuel price changes.[8]

Q. What do you conclude regarding this condition?

A. I conclude that so long as the ECAC treats all sources of generation equally and allows the recovery of energy costs from all sources, it complies with this condition.

C. Management of Price Volatility

Q. What is the third requirement established in Act 162?

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8 Braulio L Baez, "Customer Bulletin," Florida Public Service Commission, April 2004.

A. This requirement requires "the public utility to mitigate the risk of sudden or frequent fuel cost changes that cannot otherwise reasonably be mitigated through other commercially available means, such as fuel hedging contracts."

Q. What are the potential impacts of hedging fuel costs?

A. There are no free lunches in risk management. Hedging of oil by HECO would not be expected to reduce fuel and purchased energy costs and in fact would be expected to increase the level of such costs. Hedging has real costs to the party that wishes to reduce its exposure to price movements. In some years, ratepayers may benefit from a price hedge as prices rise, but in times when prices do not rise or fall, this will not be the case. In the long run, hedging programs can be expected to increase the overall level of costs associated with fuel and purchased energy expenses. Accordingly, if there is a mandate for the utility to reduce ratepayers' exposure to the potential rise in fuel costs, these hedging costs should be passed onto ratepayers. While the Company works hard to procure fuel at the lowest possible cost, HECO does not have any meaningful control over the fundamental market conditions affecting fuel cost increases and market volatility.

Q. What factors prevent HECO from undertaking a hedging program?

A. First, hedging involves cost and these costs are in addition to the cost to acquire the fuel. Customers can expect to pay more on average if HECO is mandated to adopt a hedging strategy, which in turn increases the predictability of fuel prices which may not be perceived as beneficial by all customers.

Secondly, hedging is imperfect. Perfect hedges can only be accomplished when the hedged asset is identical to the acquired asset and when the volume to be acquired is certain. This would pose basis risk if HECO could not buy financial instruments that correspond exactly to the product. Basis risk is the difference in the price movement between the derivative used to hedge and the price movement of the underlying asset. It is my understanding that there are no market-traded hedging instruments for Singapore low sulfur waxy residual ("LSWR"), which is the market index used to price the low sulfur fuel oil used by the Company. HECO's customers would therefore be exposed to considerable basis risks if it used the oil derivatives that are readily-available in the marketplace. For HECO's customers, the basis risk is substantial because both the indices in HECO's oil contracts and the available derivatives are not traded in the most liquid and transparent derivative markets.

When a regulated utility hedges, it is best done in liquid, transparent markets. Even in oil markets where market-traded hedging instruments are readily available, the liquidity of standard financial hedging products with a term of over a year are limited, and while HECO could partially hedge against oil price risk for periods of perhaps a year or so into the future, there would be considerable costs to doing so.

Q. Act 162 recognizes that there are alternatives "commercially available" to customers that can mitigate price risk for customers. How can a utility mitigate the risk of fuel cost changes?

A. There are two forms of hedges:

1. Physical hedges, such as long-term supply and purchased energy contracts and maintaining fuel inventories. The costs of existing contracts are included in the current ECAC computations.

2. Financial hedges. Generally, financial hedges either require payment to intermediaries in cash to bear risks or otherwise pay through giving up the prospect for lower future fuel prices. If utility ratepayers are willing to pay for the additional service of hedging their price risk, the ECAC would be expected to include these costs.

Q. Are there alternatives to price risk hedging available that can provide similar rate smoothing benefits?

A. Yes. There are alternatives to price hedging, such as budget billing plans and fixed rate plans.

Q. What is budget billing?

A. Budget billing is an optional payment program that allows the customer to pay the same amount each month for electricity or natural gas usage throughout the entire year. The voluntary nature of these programs limit any negative consumer feedback and target the program to the consumers that want it. A monthly bill based upon previous usage patterns is estimated for the upcoming year.[9] At the

[9] Some programs have more frequent adjustments (such as quarterly).

end of the year, there is a true-up between the amount paid by the ratepayer and the amount the ratepayer would have paid, given his actual usage, under a non-budget billing rate plan. Budget billing is typically offered to residential and small commercial customers as part of a plan to manage volatile changes in monthly energy costs. It should be noted that budget billing does nothing to mitigate rising electricity costs. Participants still pay the full amount for electricity, only the timing of payments over the course of the year is adjusted. Most states currently have a form of budget billing program available to residential customers.

Q. Please describe the other rate option, fixed rate billing.

A. Some states have allowed utilities to have a rate option called "fixed rate" or "flat bill" in which a customer pays a fixed rate per kWh with no reconciliation, but with a risk premium. Fixed rate billing programs are generally available for larger commercial and industrial users who value (and are willing to pay for) insulation from unexpected price increases.

The risk premium is necessary because fixed rate billing presents risks and additional costs to the utility. If fuel and purchased energy prices are higher than expected, fixed rate billing will under-collect. The opposite is also true. Therefore, customers electing a fixed rate billing option may force the utility to hedge against a position in the market for the underlying oil commodity. If a utility offering a fixed rate or flat bill program did not hedge against this fixed price obligation, they would be effectively speculating on the fuel markets. The fuel costs faced by HECO are largely outside the Company's control. Thus, any expected costs that would result from a fixed rate billing program would increase the flat bill rate over the regular tariff structure. The risk premium would need to be large enough to compensate the utility for any added risks and costs on average, but during periods of rising fuel prices, a large group of ratepayers taking out a fixed rate may affect a utility's liquidity and its financial health.

Fixed rate billing may provide benefits to larger customers similar to budget billing (rate stability) with the added benefit of insulation from input cost increases. Rates would, on average, be higher for the customers who select this option.

Q. What do you conclude regarding the ECAC's compliance with the third condition of Act 162?

A. There is no compelling reason for HECO to use fuel price hedging. There is no particular business reason for HECO to hedge and the benefits to customers are unclear. Even if rate smoothing were to be a desired policy goal, there likely are more effective means of meeting the goal.

Fuel (oil) hedging by HECO will be expected to result in increased customer costs and as such should only be seriously considered if there is a countervailing benefit.

Fuel hedging by HECO may be able to reduce oil price-induced fluctuations in customer rates, but would not eliminate such fluctuations. While rate stability may be a countervailing benefit to the costs of hedging, hedging will provide, at best, more and not absolute rate stability.

Limitations on HECO's ability to hedge that are a function of marketplace realities and the implications of hedging on its financial position are important considerations.

If there is a demand from customers and/or a mandate from the Commission acting on behalf of ratepayers, then recovery of the hedging and risk premium costs associated with physical and financial hedges would necessarily have to be included in the ECAC.

If fuel hedging were to be implemented, fuel hedging objectives would need to be developed in close consultation with regulators and customers and approved a priori as hedging by HECO on behalf of customers and not for HECO's shareholders account. If HECO were to implement fuel hedging it should be well understood that the Company would not be expected to speculate by attempting to time the market to minimize oil purchase costs.

There are other alternatives available, such as budget billing and fixed rate billing, which may provide the benefits sought through hedging programs (rate stability), and which would not require pursuing these potentially costly options.

D. Preservation of Utility Financial Integrity

Q. What is the fourth requirement of Act 162?

A. The fourth requirement is to "[p]reserve, to the extent reasonably possible, the public utility's financial integrity."

Q. How does a FAC generally, and the ECAC specifically, preserve the financial integrity of a utility and HECO in particular?

A. For modern utilities that operate in a world of volatile fuel prices, a FAC is critical to:

- Reduce the volatility of utility earnings. Companies exhibiting large earnings volatility are typically those with most difficulty in tracking input costs.

- Provide the utility with a reasonable opportunity to recover its prudently-incurred costs in rates.

- Lower the risks to capital invested in a utility and thus lower the utility's cost of capital (and ultimately, rates) as well as help maintain the utility's credit rating.[10] Volatile wholesale power and oil and gas commodity markets have led the rating agencies to more closely scrutinize cost-recovery mechanisms. Credit rating agencies, for example, recognize the need for robust and frequently updated FAC mechanisms. Exhibit HECO-S-10B01 presents a selection of statements from the three major credit rating agencies detailing the critical role of power cost recovery in their credit rating evaluation process.

[10] Again, most of any particular utility's peers also have a FAC and therefore a lack of a FAC would increase a utility's risk relative to its peers.

- Maintain HECO's ability to raise capital. Because oil, and other fuel expenses, are a large portion of HECO's operational costs (see Figure 2 on page 29 below), the ECAC is necessary because it allows HECO to raise capital at a reasonable cost in good markets and bad.

Utility regulators have long recognized the crucial role that cost-recovery mechanisms play in allowing the utility an opportunity to recover its costs. A FAC helps to ensure that a utility has a sufficient opportunity to earn a fair return on equity, and is needed to help the Company maintain its overall financial health so that it can effectively compete for the capital it needs in good markets and bad, particularly given that nearly all similarly situated utilities have implemented FACs. Colorado provides an example of the commission balancing the concerns of the utility and its customers. The Colorado PUC explained their long-term use of FAC mechanisms by stating that they established their FAC in order to permit rapid recovery of increased costs over which the utility has no control. The Colorado PUC recognized that unless increased fuel costs were passed through to customers expeditiously, the utility would undergo a serious erosion of earnings jeopardizing the utility's ability to provide service.[11]

When approving the Arizona Public Service Company's ("APS") proposed Power Supply Adjustor, the Arizona Corporation Commission stated "we agree that the use of an adjustor when fuel costs are volatile prevents a utility's financial condition from deteriorating" and that "an adjustor that works correctly, over time, reduces the volatility of a utility's earnings and the risk reduction can be reflected in the cost of equity in a rate case and result in lower rates."[12]

The Missouri Public Service Commission stated, "there is no dispute that the implementation of a fuel adjustment clause will reduce the level of operating risk."[13] The Missouri commission goes on to say, "[t]hat the mainstream of regulation recognizes a utility must be able to recover its prudently incurred fuel costs and that it is impossible for a utility to earn its allowed return on equity in a rising cost environment without a fuel adjustment clause."[14]

Q. Do utilities with a bond rating in the broad "BBB/Baa" credit rating category face higher capital costs in the current financial environment?

A. Yes. While the electric utility industry has not been especially hard hit by the credit crisis, they have faced increased borrowing costs when they have raised

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[11] Before the Public Utilities Commission of the State of Colorado, "In the Investigation of Electric Cost Adjustment Clauses For Regulated Electric Utilities," Docket No. 93I-702E, Decision No. C95-248, February 6, 1995.

[12] Before the Arizona Corporation Commission, "In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return, and For Approval of Purchases Power Contract," Docket No. E-01345A-03-0437, Decision No. 67744, pp. 16-17.

[13] Before the Missouri Commission, "In the Matter of Union Electric Company d/b/a AmerenUE's Tariffs to Increase Its Annual Revenue for Electric Service." Case No. ER-2008-0318, Tariff Nos. YE-2008-0605, p. 17.

[14] Id., p. 32.

capital in the market. This is particularly true of utilities that are rated "BBB+/Baa1" or lower by Standard and Poor's ("S&P) or Moody's.

In the case of HECO, S&P recently revised its "outlook" to negative. Standard and Poor's downgraded HECO's senior unsecured debt on May 23, 2007. Figure 1 depicts HECO's current bond ratings.

Figure 1 - HECO Historical Credit Ratings

	Standard and Poor's	Moody's
Long-term Issuer	"BBB" Affirmed 5/27/2009	"Baa1" Affirmed 11/15/2003
Senior Unsecured	"BBB" Downgrade 5/23/2007	---

Given these credit ratings and the ongoing credit crisis, the Company faces an increased pressure on borrowing costs.

Q. Have the credit rating agencies discussed the Company's ECAC?

A. Yes. Standard and Poor's commented on the effect of the ECAC in 2007 stating:

> Of some concern is Hawaii's Act 162, a new law which appears to confirm, in light of the state legislature's interest in promoting renewable energy, the PUC's ability to authorize the utility's fuel adjustment clause. Although no parties to the rate case seem to oppose the continuation of the clause, a material change to the fuel adjustment mechanism would harm the company's financial condition and detract from its currently satisfactory profile.[15]

Q. What do you conclude regarding the ECAC's role in preserving HECO's financial integrity?

A. The ECAC serves to mitigate the capital market challenges by reducing earning volatility and therefore boost credit ratings. Continuation of the ECAC would allow HECO to more readily raise capital in the future, which will improve its ability to meet future infrastructure needs and preserve the level of service demanded by its ratepayers and the Commission. HECO recognized this fact when it stated in its most recent 10-K that:

> Risks, uncertainties and other important factors that could cause actual results to differ materially from those in forward-looking statements and from historical results include, but are not limited to…fuel oil price changes, performance by suppliers of their fuel oil delivery obligations and the continued availability to the electric utilities of their energy cost adjustment clauses [ECACs].[16]

E. Minimize Regulatory Costs

Q. What is the fifth and final requirement established by Act 162?

A. The fifth requirement is to "[m]inimize, to the extent possible, the public utility's need to apply for frequent applications for general rate increases to account for the changes to its fuel costs."

Q. How does the ECAC help minimize regulatory costs and meet this condition?

A. In general, FACs are designed to reduce regulatory costs by separating the volatile fuel, purchased energy, and distributed energy costs from the rate proceedings. A prime motivation for FACs is a reduction in general rate cases.

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[15] Standard and Poor's, *RatingsDirect*. S&P, "Reseach Update: Hawaiian Electric Ratings cut to 'BBB': Outlook Stable." Eiseman, Barbara (May 23 2007), p 2.

[16] Hawaiian Electric, SEC Form 10-K for the period ending December 31, 2008, p. 8.

The reduction of frequent general rate cases does not reduce the Commission's oversight of HECO's fuel and purchased energy expenditures. Electric FACs allow for recovery of carefully-defined categories of fossil fuel costs, nuclear fuel costs, purchased energy, fuel transportation costs, and hedging costs, among others. Calculations supporting the ECAC are submitted to the Commission for review on a monthly basis.

SECTION III: BACKGROUND ON FUEL ADJUSTMENT MECHANISMS

F. Historical Context

Q. How did FACs become a common regulatory practice in the U.S.?

A. FACs were initially established as a response to specific shocks, such as high coal prices following WWI and inflation following WWII.[17] By the late 1950s, FACs were commonplace, albeit infrequently used for actual rate changes due to relatively stable input costs. The OPEC oil crisis of 1972-73, however, put FACs back in the spotlight. Many state regulators began pushing for uniformity across their states. By 1990, 40 jurisdictions had long-standing FACs in place.[18] In Hawaii, an oil cost recovery charge has been in place since at least the 1920s.[19]

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[17] See: Michael Schmidt, *Automatic Adjustment Clauses: Theory and Application* (East Lansing, MI: MSU, 1980), pp. 10-11.

[18] Robert Burns, Mark Eifert and Peter Nagler. "Current PGA and FAC Practices: Implications for Ratemaking in Competitive Markets," *National Regulatory Research Institute*, November 1991, p. 9. (Hereinafter referred to as the "NRRI Report.")

[19] The Hawaii Electric Co.'s tariffs for 1928 show that "[t]he rates set forth in this schedule are based on the cost to the Company of fuel oils delivered in the Company's tanks at Two Dollars ($2.00) per …

G. Three Classic Reasons for Fuel Adjustment Mechanisms

Q. What accounts for the common use of FACs?

A. FAC mechanisms (and other cost-adjustment mechanisms) give utilities a reasonable opportunity to recover their legitimate costs of procuring electricity on behalf of customers. By providing timely cost recovery for power costs, the amount of time between rate cases—called "regulatory lag"[20]—can increase. The three classic reasons for a FAC include:

1) The purchased item (most commonly fuel) is outside the control of the buying utility.

2) The item is a significant or large component of the utility's total operating costs.

3) The cost changes with respect to that item can be volatile and unpredictable.[21]

It is not necessary that individual cost items be large, volatile and unpredictable to qualify for FAC treatment. An effective FAC covers all purchased energy costs, including renewable sources, on an equal footing.

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barrel. For each advance of one whole cent per barrel in excess of $2.00 per barrel of fuel oil, an additional charge of $0.00004 per kWh will be made for all current supplied in excess of 5000 kWh per month." A similar reduction occurred if oil prices dropped. *See*: Tariffs for The Hawaii Electric Co, Ltd. Revised Sheet No. 53, Issued July 1, 1928, Schedule P-1.

[20] Between rate cases, utility managements have an incentive to control costs, seek new efficiencies, and avoid wasteful or unnecessary expenses. The longer they anticipate that period will be, the stronger the incentive. The reason is simple: until the next rate case is decided they get to keep any additional earnings generated.

Q. Please explain the first classic reason to support an FAC.

A. Utilities procure fuel from markets and would normally not have the ability to control the price set in those markets. The 1991 NRRI Report notes that "[u]nless a utility is vertically integrated so that it owns the fuel source (whether it is the coal mine, gas well, or others), it is unlikely that the utility can exert much control over the cost of the fuel."[22] Moreover, the utility does not normally have the ability to control its customers' demand. It must procure the fuel and purchased energy that are needed to meet customer demand as part of its obligation to serve.

The utility, of course, has an obligation to procure its fuel and purchased energy from the energy markets in a prudent manner. The NRRI Report notes that the utility is not "excused from hard-nosed, tough bargaining" and goes on to explain that state public utility commissions often hold utilities to a standard of prudent care in negotiating fuel contracts before allowing the cost to flow through a fuel adjustment or purchased gas adjustment clause.

Given prudent management, if certain costs (called "exogenous costs") are not within the control of the utility, the pursuit of economic efficiency calls for no penalty or gain to be borne by the utility as a result of changing market conditions. Exogenous cost changes represent any change in the cost of the firm—up or down—that is beyond the control of the firm. In a competitive

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[21] NRRI Report, p. 9.

[22] NRRI Report, p. 4.

industry, if these costs were required to provide a service, cost changes would alter the long run marginal and average cost curves of the industry and would directly affect the market price prevailing in the industry. Because exogenous costs are not under the control of the firm, passing such cost changes through to customers automatically cannot affect the incentive of the firm to behave efficiently or the market price standard to which regulated policies aspire. The pass-through of exogenous costs permits the regulated firm's prices to reflect market conditions (for the prices of its inputs) in just the way that input cost changes affect prices in unregulated, competitive markets, while providing a market price signal to customers.

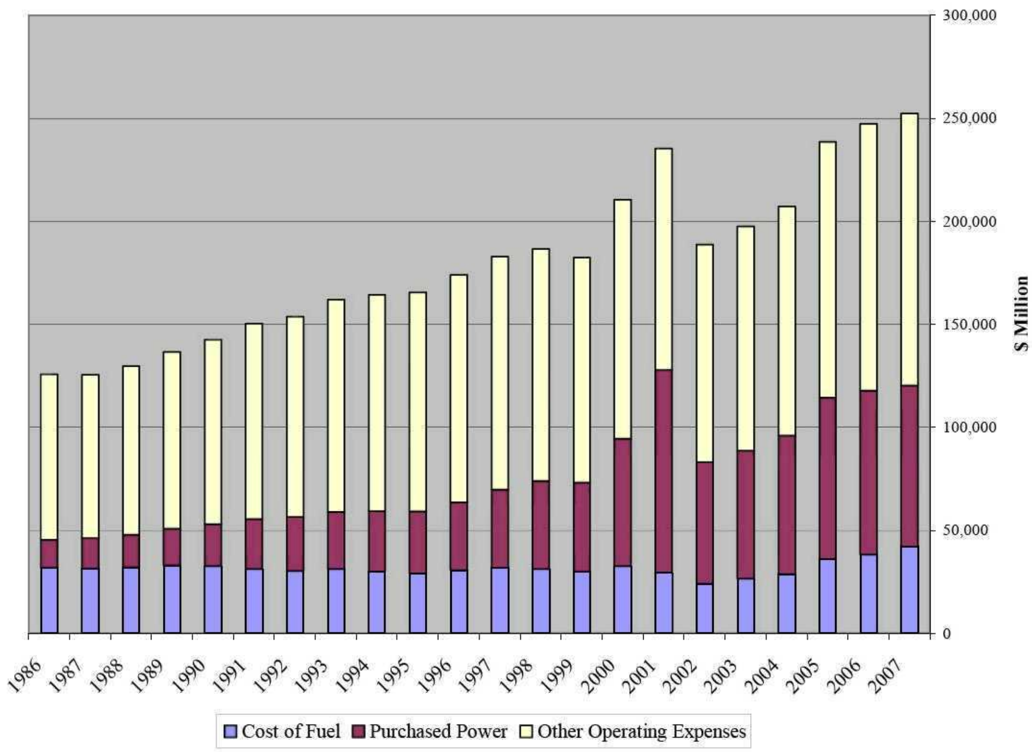
Q. Please explain the second classic reason to support an FAC.

A. Fuel and purchased energy costs continue to be a significant component of a utility's total operating costs. For all major investor-owned utilities ("IOUs") in the US, the average proportion of fuel and net purchased energy relative to total operating expenses ranged from 35.8 to 54.3 percent during the 1986 to 2007 period.[23] Total fuel and net purchased energy averaged 40.84 percent for the 1986-2007 period, as shown in Figure 2. The continued high proportion of fuel and purchased energy costs relative to total operating costs shows that there is a continuing role for FACs as a tool for timely recovery of fuel and purchased energy costs. HECO's fuel and purchased power expenditures represented about

[23] Energy Information Administration, Electric Power Annual 2007, p. 49, Table 8.1 Revenue and Expense Statistics for Major U.S. Investor-Owned Electric Utilities, 1992 through 2007, January 2009. *See*: http://www.eia.doe.gov/cneaf/electricity/epa/epa.pdf (Accessed on July 14, 2009).

64 percent of Energy Operating Expenses in 2008, up from 37 percent ten years ago in 1998.[24]

Figure 2. Fuel and Net Purchased Power Costs and Other Operating Expenses for U.S. Investor Owned Utilities, 1986-2007 [25]



Q. Please explain the third classic reason to support an FAC.

A. Changes in fuel and purchased energy costs can be volatile and unpredictable. Although HECO is isolated from the wholesale electricity and natural gas markets, its primary source of fuel and purchased energy expenses are dependent

[24] Hawaiian Electric SEC Form 10-K for the period ending December 31, 2008.

[25] Energy Information Agency. *Electric Power Annual, Vol. II*. "Revenue and Expense Statistics for Selected Investor-Owned Electric Utilities": Table 8.1 (1992-2007), Table 11 (1990-1994), Table 34 (1986-1990).

upon the market price for oil, which constitutes about 76.7 percent of HECO's fuel mix.[26]

State commissions continue to cite the unpredictable nature of fuel and purchased energy costs that, if unaccounted for, would leave the utility to bear the burden and financial risk of volatility. For example, the Louisiana Public Service Commission states that the "Fuel Adjustment Clause mechanism…has been established due to the materiality and historical and potential volatility of these costs."[27]

A utility must serve its customers under all weather and energy market conditions and therefore must purchase fuel and power to satisfy demand during peak periods during the year (*i.e.*, unusually cold winter days or warm summer days). Recent history has shown that events outside a utility's control can increase the volatility of oil, purchased energy and other fuel prices.

H. Current Status of FACs in U.S.

Q. What is the current status of power cost recovery in the United States?

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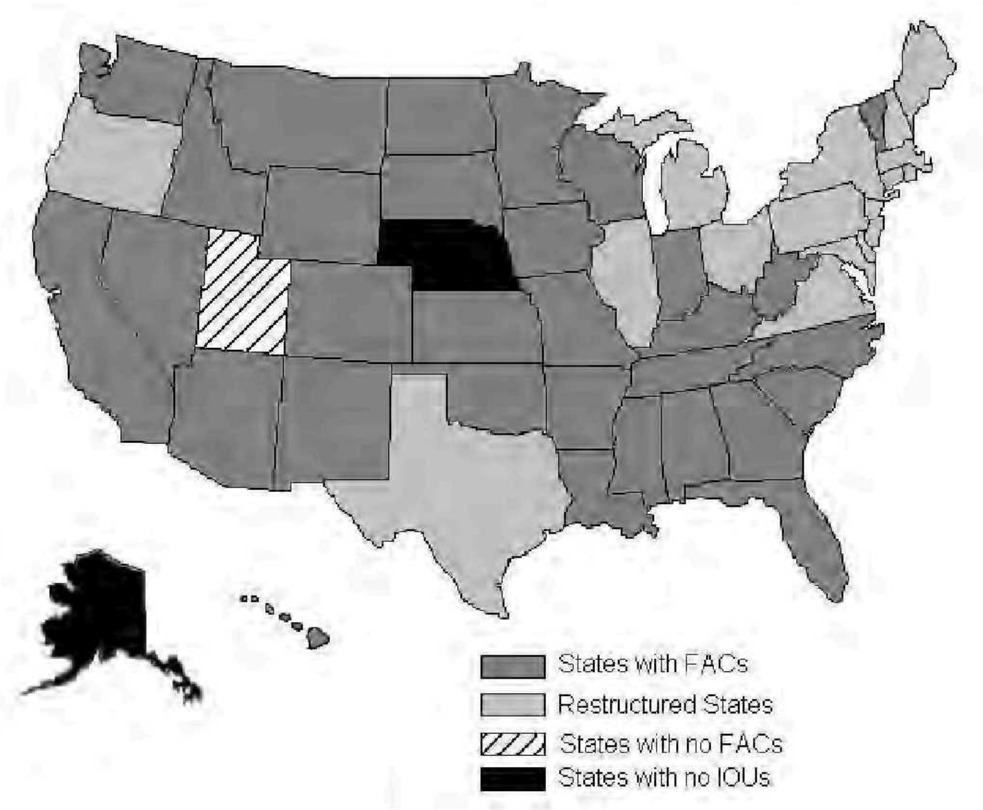
[26] HECO website, About Our Fuel Mix, Available at: http://www.heco.com/portal/site/heco/menuitem.508576f78baa14340b4c0610c510b1ca/?vgnextoid=047a5e658e0fc010VgnVCM1000008119fea9RCRD&vgnextchannel=deeaf2b154da9010VgnVCM10000053011bacRCRD&vgnextfmt=default&vgnextrefresh=1&level=0&ct=article (Accessed July 14, 2009).

[27] Before the Louisiana Public Service Commission, "Development of standards governing the treatment and allocation of fuel costs by electric utility companies," General Order, Docket No. U-21497, October 1, 1997.

A. FACs are prevalent throughout the U.S. Of the 32 traditionally regulated states, only Utah lacks a FAC.[28] Many states have instituted state-wide FAC mechanisms available to all electric (or gas) utilities. Some states have dealt with each utility on a case-by-case basis, which has led to inconsistencies across utilities within these states regarding power cost adjustments. Figure 3 summarizes the current status of FACs.

Figure 3. Current Status of Fuel Cost Adjustments in the U.S.



[28] Most electric restructuring states have implemented some mechanism to pass through Provider of Last Resort ("POLR") or Standard Offer Service ("SOS") charges.

Q. Have many states that lacked an FAC established or reestablished an FAC in recent years?

A. Yes. Nearly every state regulatory commission has ruled in favor of the FAC. Many states that previously revoked their FAC have reinstated in recent years. Figure 4 lists the states that have recently reinstated an FAC for an electric utility in the state.

Figure 4. Recently Implemented Fuel Adjustment Mechanisms, 2007-2009.

State	Utility	Date
Arizona	Tucson Electric Power	Dec-08
Missouri	Empire Electric	Jul-08
Missouri	AmerenUE	Feb-07
Missouri	Aquila	May-07
Montana	MDU Resources	Apr-08
New Mexico	PS New Mexico	May-07
Oregon	Portland General	Jan-07
Vermont	Central Vermont PS	Sep-08
Viginia	Potomac Edison	Apr-208
West Virginia	Monongahela Power	May-07
West Virginia	Potomac Edison	May-07

Q. What do you conclude regarding the use of FACs?

A. Fuel prices constitute a large and volatile cost for price-taking utilities. A well-established, frequently-updated FAC is essential to maintain a utility's credit and operational viability and thereby meet the requirements of customers.

Q. Does this conclude your testimony?

A. Yes, it does.

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Dr. Makholm concentrates on the issues surrounding the privatization, regulation and deregulation of energy and transportation industries—those that operate networks (such as oil and gas pipelines, electricity transmission and gas distribution systems, telecommunications and water utility systems) and those operating infrastructure business at specific sites, such as airports, electricity generation plants, oil refineries, gas treatment plants and sewage treatment plants. These issues include the broad categories of efficient pricing, market definition and the components of reasonable regulatory practices. Specific pricing issues include tariff design, incentive ratemaking, and the unbundling of prices and services. Issues of market definition include assessments of mergers, including the identification and measurement of market power. Issues of reasonable regulatory practices include the creation of credible and sustainable accounting rules for ratemaking as well as the establishment of administrative procedures for regulatory rulemaking and adjudication. On such issues among others, Dr. Makholm has prepared expert testimony, reports and statements, and has appeared as an expert witness in many state, federal and U.S. district court proceedings as well as before regulatory bodies and Parliamentary panels abroad.

Dr. Makholm's clients in the United States include privately held utility corporations, public corporations and government agencies. Focusing mainly in the areas of gas and electric utilities, he has represented dozens of gas distribution utilities, as well as both intrastate and interstate gas pipeline companies and gas producers. Dr. Makholm has also worked with many leading law firms engaged in natural gas and electricity issues.

Internationally, Dr. Makholm has directed an extensive number of projects in the utility and transportation businesses in 20 countries on six continents. These projects have involved work for investor-owned and regulated business as well as for governments and the World Bank. These projects have included advance pricing and regulatory work prior to major gas, railroad and toll highway privatizations (Poland, Argentina, Bolivia, Mexico, Chile and Australia), gas industry restructuring and/or pricing studies (Canada, China, Spain, Morocco, Mexico and the United Kingdom), utility mergers and market power analyses (New Zealand), gas development and and/or contract and financing studies (Tanzania, Egypt, Israel and Peru), regulatory studies (Chile, Argentina), and oil pipeline transport financing and regulation (Russia). As part of this work, Dr. Makholm has prepared reports, drafted regulations and conducted training sessions for many government, industry and regulatory personnel.

Dr. Makholm has published a number of articles in Public Utilities Fortnightly, Natural Gas and The Electricity Journal—many involving emerging issues of wholesale and retail competition in gas and electricity, including the issues of unbundled and competitive transport, secondary markets and stranded costs. He is a frequent speaker in the U.S. and abroad at conferences and seminars addressing market, pricing and regulatory issues for the energy and transportation sectors.

EDUCATION

UNIVERSITY OF WISCONSIN-MADISON,
MADISON, WISCONSIN
Ph.D., Economics, 1986
Dissertation: Sources of Total Factor Productivity in the Electric Utility Industry
M.A., Economics, 1985

BROWN UNIVERSITY
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Graduate Study, 1980-1981

UNIVERSITY OF WISCONSIN-MILWAUKEE
MILWAUKEE, WISCONSIN
M.A., Economics, 1980
B.A., Economics, 1978

EMPLOYMENT

1996-present	Senior Vice President. National Economic Research Associates, Inc., (NERA) Boston, Massachusetts.
1986-1996	Vice President/Senior Consultant. National Economic Research Associates, Inc., (NERA) Boston, Massachusetts.
1987-1989	Adjunct Professor. College of Business Administration, Northeastern University, Boston, Massachusetts
1984-1986	Consulting Economist. National Economic Research Associates, Inc., (NERA) Madison, Wisconsin.
1983-1984	Consulting Economist. Madison Consulting Group, Madison, Wisconsin.
1981-1983	Staff Economist. Associated Utility Services, Inc., Moorestown, New Jersey.

RECENT TESTIMONY (SINCE 2000)

Before the New York State Public Service Commission, Direct Testimony on behalf of RG&E Corporation. Case No 09-E-__. January 27, 2009. Subject: Cost of equity capital.

Before the New York State Public Service Commission, Direct Testimony on behalf of NYSEG Corporation. Case No 09-E-__. January 27, 2009. Subject: Cost of equity capital.

Before the Department of Public Utility Control of Connecticut, Direct Testimony on behalf of Connecticut Natural Gas Corporation. Docket No. 08-12-06. January 11, 2009. Subject: Cost of capital.

Before the Department of Public Utility Control of Connecticut, Direct Testimony on behalf of Southern Connecticut Gas Corporation. Docket No. 08-12-06. January 11, 2009. Subject: Cost of capital.

Before the Public Utility Commission of Texas, Rebuttal Testimony on behalf of Lone Star Transmission, LLC. Docket No. 35665. November 14, 2008. Subject: Licensing of new electricity transmission projects.

Before the Public Utilities Commission of Ohio, Direct Testimony on behalf of The Dayton Power and Light Company. Case No. 08-1094-EL-SSO. October 10, 2008. Subject: Cost of capital.

Before the Illinois Commerce Commission, Rebuttal Testimony on behalf of Northern Illinois Gas Company, Case No. 08-0363. September 25, 2008. Subject: Cost of capital.

Before the Illinois Commerce Commission, Testimony on behalf of Northern Illinois Gas Company, Case No. 08-0363. April 29, 2008. Subject: Cost of equity.

Before the Illinois Commerce Commission, Rebuttal Testimony on behalf of Shelby Coal Holdings, LLC, Christian Coal Holdings, LLC and Marion Coal Holdings, LLC. Docket No. 07-0446. April 7, 2008. Subject: Pipeline certification and competition in pipeline transport market.

Before the New York State Public Service Commission, Rebuttal Testimony on behalf of Iberdrola, S.A., Energy East Corporation, RGS Energy Group, Inc., Green Acquisition Capital, Inc., New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation, Case No. 07-M-0906. January 31, 2008. Subject: Regulatory philosophy/ merger issues.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Sierra Pacific Power Company, Docket No. 07-09016. January 14, 2008. Subject: Stand-alone costs and cost allocation issues.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Sierra Pacific Power Company. Docket No. 07-09016. January 11, 2008. Subject: Allocation of pipeline transport costs.

Before the Illinois Commerce Commission, Testimony on behalf of Shelby Coal Holdings, LLC, Christian Coal Holdings, LLC and Marion Coal Holdings, LLC. Docket No. 07-0446. January 7, 2008. Subject: Pipeline certification and competition in pipeline transport market.

Before the Federal Energy Regulatory Commission, Affidavit on behalf of Consolidated Edison Company of New York, Docket No. OA08-13-000. January 7, 2008. Subject: Planning and allocation of electric transmission costs.

RECENT TESTIMONY (SINCE 2000 CONTINUED)

Before the Public Utilities Commission of Nevada, Direct Testimony on behalf of Sierra Pacific Power Company, Docket No. 07-09016. December 14, 2007. Subject: Stand-alone costs and cost allocation issues.

Before the New Hampshire Public Service Commission, Docket No.. DE 07-064, invited appearance on an expert panel to present perspectives and answer questions on policies and practices regarding retail gas and electric distribution rate "decoupling," November 7, 2007.

Before the Public Utilities Commission of Nevada, Prefiled Direct Testimony on behalf of Sierra Pacific Power Company, Docket No. 07-05019. May 15, 2007. Subject: Prudence of gas purchase costs.

Before the United States Bankruptcy Court, Southern District of New York, Supplemental Report on behalf of Solutia, Inc., *et al.*, Debtors, Case No. 03-17949 (PCB) (Jointly Administered), April 20, 2007. Subject: Discount rate for contract rejection damages.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Sierra Pacific Power Company, Docket No. 06-12001. April 19, 2007. Subject: Stand-alone costs and cost allocation issues.

Before the United States Bankruptcy Court, Southern District of New York, Supplemental Report on behalf of Solutia, Inc., et al., Debtors, Case No. 03-17949 (PCB) (Jointly Administered), March 23, 2007. Subject: Discount rate for contract rejection damages.

Before the United States District Court, District of Kansas, Expert Report on behalf of J.P.Morgan Trust Company, *et al.* in the matter of J.P. Morgan Trust Company, *et al.* V. Mid-America Pipeline Company, *et.al.*, Docket No. 05-CV-2231-CM/JPO. March 21, 2007. Title: “Harm to Farmland’s Coffeyville Refinery Expert Report”, by Jeff. D. Makholm.

Before the Public Utilities Commission of Nevada, Prefiled Direct Testimony on behalf of Nevada Power Company, Docket No. 07-01022. January 16, 2007. Subject: Prudence of gas purchase costs.

Before the Public Utilities Commission of the State of Hawaii, Supplemental Testimony on behalf of Hawaii Electric Light Company, Inc., Docket No. 05-0135. December 29, 2006. Subject: Energy cost adjustment clause.

Before the Public Utilities Commission of the State of Hawaii, Testimony on behalf of Hawaiian Electric Company, Inc., Docket No. 2006-0386. December 22, 2006. Subject: Energy cost adjustment clause.

Before the Public Utilities Commission of Nevada, Pre-filed Direct Testimony on behalf of Sierra Pacific Power Company, Docket No. 06-12001. December 1, 2006. Subject: Stand-alone costs and cost allocation issues.

Before the State of New Jersey Board of Public Utilities, Prepared Reply Testimony on behalf of Public Service Electric & Gas, OAL Docket No. PUC1191-06 and BPU Docket No. EO05111005. November 3, 2006. Subject: Unregulated contract prices for telecommunication conduit rental contracts.

Before the State of New Jersey Board of Public Utilities, Rebuttal Testimony on behalf of the New Jersey American Water Company, Case No. WR06030257, October 10, 2006. Subject: Cost of Capital.

RECENT TESTIMONY (SINCE 2000 CONTINUED)

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Sierra Pacific Power Company, Docket No. 06-05016. October 2, 2006. Subject: Prudence of gas purchase costs.

Before the Federal Energy Regulatory Commission, Reply Testimony on behalf of the State of Alaska, Docket No. OR05-2-001, August 11, 2006. Subject: Relative risk and capital structure for the Trans Alaska Pipeline System (TAPS).

Before the Maine Public Utilities Commission, Response to the Bench Analysis on behalf of Central Maine Power Company, Docket 2005-729. May 19, 2006. Subject: Specification of productivity offset for price cap formula.

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"Precios del Gas Natural para la Generación de Electricidad en el Perú" (November 16th, 1998). This report analyzes different alternatives for the treatment of natural gas prices in the electricity tariff model (report in Spanish).
"Tariffs and Subsidies: Report for the Tariffs Group" (November 10th, 1998). This report presents recommendation on the path for tariffs and subsidies for 1999 to the Electricity Tariffs Group of the Government of Mexico.

"Gasoducto México-Guatemala: Informe Final" (October 22nd, 1998). This report analyzes the legal and regulatory framework in both Mexico and Guatemala and costs and volumes for the building of a natural gas pipeline connecting both countries. A copy of the report was given by President Zedillo (Mexico) to President Arzú (Guatemala) (report in Spanish).

"Checks and Balances in Regulating Power Pools: Seven case Studies. A Report for the Electricity Pool of England and Wales" (September 10th, 1998). This report surveys the regulation of power pools in electricity industries around the world.

"Fuels Policy Group: Recommendations" (September 11th, 1998). This report presents recommendations to the Government of Mexico on their fuels policies for the electricity sector.

"Análisis de Costos e Inversiones. Revisión Tarifaria de Transener" (August 25, 1998). Report given to ENRE (the Argentinean electricity regulator) on behalf of a Consortium of Generators on the analysis of costs and investments to be considered for the revenue requirement of the electricity transmission company (report in Spanish).

"Central America Pipeline: Regulatory Analysis and Proposal" (July 28, 1998). This report presents the regulatory analysis and development of a fiscal, legal and commercial framework proposal for gas import, transportation, distribution and marketing in El Salvador, Honduras and Guatemala regarding the proposed Central American Pipeline.

"Energy Regulation in El Salvador" (July 28, 1998). This report presents a deep analysis of the electricity and natural gas regulatory, legal and tax frameworks in El Salvador.

RECENT INTERNATIONAL REPORTS (CONTINUED)

"Energy Regulation in Guatemala" (July 28, 1998). This report presents a deep analysis of the electricity and natural gas regulatory, legal and tax frameworks in Guatemala.

"The Cost of Capital for Gas Transmission and Distribution Companies in Victoria" (June 22, 1998). Report prepared for BHP Petroleum Pty Ltd.

"Principios Económicos Básicos de Tarificación de Transmisión Eléctrica. Revisión Tarifaria de Transener" (May 26, 1998). The main purpose for this report was to provide an economic and regulatory analysis of laws, decrees, license and documents of the tender to provide advise in the tariff review of Transener (the electricity transmission company in Argentina), to present an economic analysis of transmission tariffs and to provide an opinion on specific topics to be discussed in the public hearing. This report was written for a consortium of generators in Argentina (reports in English and Spanish)

"Asesoría en la Fijación de Tarifas de Transener y Normativa del Transporte, Benchmarking Study" (May 26, 1998). This report compares the costs of Transener (the electricity transmission company in Argentina) with those of other companies elsewhere for a consortium of generators (the electricity transmission company in Argentina).

"International Regulation Tool Kit: Argentina" (March 20, 1998). This document describes the natural gas regulatory framework in Argentina for BG.

"Tarificación de los Servicios Que Prestan las Terminales de Gas LP" (January 9, 1998). The final report given to PEMEX Gas y Petroquímica Básica (México) for the determination of rates for LPG terminals.

"NERA-Pérez Companc Distribution Tariff Model" (January 5, 1998). This report explains the methodology behind NERA's calculations of distribution tariffs for Pérez Companc in Monterrey.

"Monterrey Natural Gas Market Assessment," (January 5, 1998). A series of reports were written to present the results of the market study of the demand for natural gas in the geographic zone of Monterrey to a company interested in bidding for the natural gas distributorship.

"Resolving the Question of Escalation of Phases (bb) and (cc) Under the Maui Gas Sale and Purchase Contract", prepared for the New Zealand Treasury, December 16, 1997.

"Timetable and Regulatory Review for the Monterrey International Public Tender," (December 5, 1997). A description of the necessary steps to bid for a distribution company as well as an explanation and analysis of natural regulations in Mexico for Pérez Companc.

"Economic Issues in the PFR for 18.3.1(I)(bb) & (cc)", prepared for the New Zealand Treasury, November 17, 1997.

"NERA's Distribution Tariff Model" (October 29, 1997). This report explains the methodology behind NERA's calculations of distribution tariffs for MetroGas.

"Evaluation Design Standards for MetroGas," (October 24, 1997). This report dealt with the analytical support resulting from work with MetroGas to create a meticulously-documented security criterion analysis that supported its efforts to obtain due recognition—and appropriate tariff treatment—for its costs.

"Ghana Natural Gas Market Assessment," prepared for the Ministry of Mines and Energy, Ghana (March-July, 1997). A series of four reports assessing prospective gas demand usage and netback prices for a number of proposed pipeline project alternatives.

RECENT INTERNATIONAL REPORTS (CONTINUED)

"Final Report for Russian Oil Transportation & Export Study: Commercial, Contractual & Regulatory Component," prepared for The World Bank, June 25, 1997.

Response to FIEL's criticisms regarding NERA's report "Cálculo del Factor de Eficiencia (X)" (June 2, 1997).

"Impacts on Pemex of Natural Gas Regulations" prepared for Pemex Gas y Petroquímica Básica México, May 21, 1997.

"Market Models for Victoria's Gas Industry: A Review of Options," April 1997, prepared for Broken Hill Proprietary (BHP) Petroleum, to propose an alternative model for gas industry restructuring in Victoria, Australia.

"New Market Arrangements for the Victorian Gas Industry," prepared for Broken Hill Proprietary Petroleum; March 13, 1997.

"CEG Privatization: Comments to the Regulatory Framework," prepared for Capitaltec Consultoria Economica SA describing our comments with respect to the regulatory framework and the license proposed in the privatization of Riogas and CEG in Rio de Janeiro, Brazil; March 7, 1997.

"Determination of the Efficiency Factor (X)," prepared for ENARGAS, Argentina, January 24, 1997.

"Determination of Costs and Prices for Natural Gas Transmission," prepared for Pemex Gas y Petroquímica Básica, México, December 19, 1996.

"Regulating Argentina's Gas Industry," a report prepared for The Ministry of Economy and The World Bank, November 26, 1996.

"Open Access and Regulation," prepared for Gascor, in the State of Victoria, Australia; (October 2, 1996).

"A Review and Critique of Russian Oil Transportation Tariffs (Russian Oil Transportation & Export Study; Commercial, Contractual & Regulatory Component)," prepared for The World Bank, June 13, 1996.

"Tariff Options for Transneft (Russian Oil Transportation & Export Study; Commercial, Contractual & Regulatory Component)," prepared for The World Bank, June 6, 1996.

"Comments on the Proposed Amendments to the Regulation of Airports in New Zealand," prepared for the New Zealand Parliament Select Committee hearings on the regulation of monopolies, March 13, 1996.

"Evaluating the Shell Camisea Project," prepared for Perupetro S.A., Government of Peru, December 8, 1995.

"Towards a Permanent Pricing and Services Regime," prepared for British Gas, London, England, November, 1995.

"Final Report: Gas Competition in Victoria," prepared for Gas Industry Reform Unit, Office of State Owned Enterprises, June 1995.

"Natural Gas Tariff Study," prepared for the World Bank, May 1995, consisting of:

Principles and Tariffs of Open-Access Gas Transportation and Distribution Tariffs
Handbook for Calculating Open-Access Gas Transportation and Distribution Tariffs

RECENT INTERNATIONAL REPORTS (CONTINUED)

"Economic Implications of the Proposed Enerco/Capital Merger," prepared for Natural Gas Corporation of New Zealand, December 1994.

"Contract Terms and Prices for Transportation and Distribution of Gas in the United States," prepared for British Gas TransCo, November 1994.

"Economic Issues in Transport Facing British Gas," prepared for British Gas plc, December 1993.

"Overview of Natural Gas Corporation's Open-Access Gas Tariffs and Contract Proposals," prepared for Natural Gas Corporation of New Zealand, October 1993.

PARTIAL LIST OF CLIENTS SERVED WORLDWIDE

ELECTRIC UTILITY

AEP Energy Services, Inc
Alberta Power Limited
American Electric Power Company
Atlantic Electric Company
Boston Edison Company
Central Hudson Gas and Electric
Central Maine Power Company
Central Power & Light Company
Commonwealth Edison Company (Unicom/Exelon)
Commonwealth Energy System
Consolidated Edison Company of New York, Inc
Conowingo Power Company
Duquesne Light Company
Edison Electric Institute
Entergy Gulf States, Inc
Florida Power and Light Company
Green Mountain Power Company
Long Island Lighting Company
Massachusetts Municipal Wholesale Electric Company
Massachusetts Electric Company
Nantahala Power Company
New York State Electric & Gas Corporation
Niagara Mohawk Power
Ohio Power Company
Orange & Rockland Utilities
Pennsylvania Power and Light Company
Pennsylvania Power Company
Philadelphia Electric Company
PJM electricity transmission owners
Public Service Company of New Hampshire
Public Service Company of New Mexico
Public Service Electric and Gas Company
Portland General Electric Company
Reliant Energy HL&P
Rochester Gas and Electric Corp.
Sierra Pacific Power Corporation
Southwest Electric Power Company
Southwestern Public Service Company
Tampa Electric Company
Texas-New Mexico Power Company
TXU Electric Company
United Illuminating Company
UtiliCorp Networks Canada
Virginia Electric and Power Company
West Penn Power Company
West Texas Utilities Company
Western Massachusetts Electric Co.

GAS UTILITY

ARKLA, Inc.
Atlanta Gas Light Company
Bay State Gas Company
Berkshire Gas Company
Blackstone Gas Company
Boston Gas Company
Bristol & Warren Gas Company
British Gas plc
Brooklyn Union Gas Company
Canadian Western Natural Gas
Chattanooga Gas Company
Colonial Gas Company
Commonwealth Gas Company
Connecticut Natural Gas Corp.
Consolidated Gas Supply Corp.
Elizabethtown Gas Company
Empire State Pipeline Company
ENAGAS (Spain)
EnergyNorth, Inc.
Essex County Gas Company
Fall River Gas Company
Fitchburg Gas & Electric Light Company
Gas and Fuel Corporation of Victoria
Gateway Pipeline Company
Granite State Gas Transmission, Inc.
Great Falls Gas Company
Holyoke, Mass. Gas & Electric Dept.
ICG Utilities (Ontario) Ltd.
KN Energy, Inc.
Middleborough Municipal Gas & Electric
National Fuel Gas Distribution Corp.
Natural Gas Corporation of New Zealand
Natural Gas Pipeline of America
Norwich Department of Public Utilities
Pacific Gas Transmission
Pemex Gas y Petroquímica Básica
Pennsylvania Gas and Water Company
Peoples Gas Light and Coke Company
Providence Gas Company
Southern Connecticut Gas Company
Southwest Gas Corporation
Transwestern Pipeline Company
Valley Gas Company
Washington Gas Light Company
Westfield Gas & Electric Light Dept.
Wisconsin Gas Company
Yankee Gas Services Company

PARTIAL LIST OF CLIENTS SERVED WORLDWIDE (CONT.)

TELEPHONE UTILITY

Centel Corporation
Chichester Telephone Company
Community Service Telephone Company
Continental Telephone Company of Illinois
General Telephone of Pennsylvania
General Telephone Company of Ohio
Kearsarge Telephone Company
Meriden Telephone Company
Pacific Bell Telephone Company
Tipton Telephone Company

PARTIAL LIST OF CLIENTS SERVED WORLDWIDE (CONT.)

REGULATORY AND GOVERNMENT

Delaware Public Service Commission
re: Delmarva Power & Light Company

District of Columbia Public Service Commission
re: Potomac Electric Power Company
Washington Gas Light Company

Massachusetts Municipal Wholesale Electric Company

The Government of Chile
Gas industry regulations

The Government of Argentina
Plan for privatized rail freight industry regulation

The Government of Tanzania
Natural gas development and regulation plan for Songo Songo Island gas reserves.
Financing the development of gas reserves on Songo Songo Island with emphasis on payment guarantee mechanisms for foreign exchange.

The World Bank
re: Natural gas tariffs for Polskie Gornictwo Naftowe i Gazownictwo (The Polish Oil and Gas Company)

re: Natural gas transport and distribution tariffs for Gas del Estado (The Argentine State-owned gas utility)

re: Natural gas development for the Moroccan Gas System.

re: Natural gas transport and distribution tariffs for the Bolivian Gas Industry.

re: Natural gas development plan for Sichuan province of China.

OTHER

Air New Zealand
BHP Petroleum Pty Ltd
Centel Corporation
General Electric Company
Intel Corporation
Jamaica Water Supply Company
Nucor Steel Corporation
Parsons Brinckerhoff Development Group

MEMBERSHIP IN PROFESSIONAL ORGANIZATIONS

The American Economic Association

HECO ST-11
DOCKET NO. 2008-0083

SUPPLEMENTAL TESTIMONY OF
PATSY H. NANBU

CONTROLLER
GENERAL ACCOUNTING
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Administrative and General Expenses;
Pension and Postretirement
Benefits Other than Pensions Tracking
Mechanisms; General
Accounting Department Staffing;
Merit Salary Adjustment in HECO's July 8, 2009 filing;
Accounting for Capital Projects Placed in Service

INTRODUCTION

Q. Please state your name and business address.

A. My name is Patsy H. Nanbu and my business address is 900 Richards Street, Honolulu, Hawaii.

Q. By whom are you employed and in what position.

A. I am Hawaiian Electric Company, Inc.'s ("HECO" or "Company") Controller. My educational background and experience are shown in HECO-1100.

Q. Have you previously testified in this proceeding?

A. Yes. I have submitted written direct testimony, exhibits and supporting workpapers as HECO T-11.

Q. Please describe what you will be covering in your supplemental testimony.

A. My supplemental testimony will present the Company's overall normalized 2009 test year estimates for Administrative and General ("A&G") Expenses, which includes Account Nos. 920-932.

I will be addressing the increase in the test year 2009 A&G expenses from the amounts in the 2007 rate case interim decision for the Administrative Expenses, Outside Services and Employee Benefits transferred in HECO-S-1103. Mr. Russell Harris (HECO ST-12) will address the increases for Insurance Expense (Account Nos. 924 and 925), Ms. Julie Price (HECO ST-13) will address the increases for Employee Benefit Expense (Account Nos. 92600 and 926010), and Mr. Bruce Tamashiro (HECO ST-14) will address the increases in Miscellaneous A&G Expenses (Account Nos. 928, 9301, 9302, 931 and 932).

In addition, I will be addressing (1) the pension and postretirement benefits other than pensions tracking mechanisms (2) the staffing for the General Accounting Department, (3) the merit salary adjustment that was reflected in the revised schedules resulting from Interim D&O HECO filed on July 8, 2009, and (4) the accounting for capital projects that are placed in service.

2009 TEST YEAR A&G EXPENSES

Q. What is the 2009 test year settlement A&G expense estimate?

A. As shown on HECO-S-1101, the total A&G expense estimate used for the settlement agreement and statement of probable entitlement is $88,948,000. The total represents the test year estimates for Account Nos. 920 through 932. The A&G expenses cover a diverse group of expenses, and can be grouped by accounts in the following categories:

		($ Thousands)
1)	Administrative (Account Nos. 920-922)	$30,422
2)	Outside Services (Account Nos. 923010 and 923020)	$ 2,666
3)	Insurance (Account Nos. 924 and 925)	$10,229
4)	Employee Benefits (Account Nos. 926000-926020)	$36,817
5)	Miscellaneous (Account Nos. 928-932)	$ 8,815
	Total A&G Expenses	$88,948

Q. How does the A&G expenses for the 2009 test year used in the settlement agreement and statement of probable entitlement compare with the amount included in the 2007 test year rate case interim decision in Docket No. 2006-0386?

A. Test year A&G expenses included in the settlement agreement of $88,948,000 is $19,759,000 more than the amount included in the 2007 test year rate case interim decision. As discussed above, the differences by the groups of accounts by categories in A&G expense and the explanations are provided by Mr. Harris (HECO ST-12), Ms. Price (HECO ST-13), Mr. Tamashiro (HECO ST-14) and I (HECO-S-1103).

PENSION AND OPEB TRACKING MECHANISMS

Pension and OPEB Background

Q. Have you previously discussed the accounting and reporting requirements for pensions and OPEB?

A. Yes, in HECO T-11, pages 66-70, I discuss the accounting and reporting requirements with respect to pension and OPEB plans.

Q. Have you previously discussed the ratemaking treatment for pension and OPEB costs?

A. Yes, in HECO-T-11, pages 70-76, I discuss the pension and OPEB tracking mechanisms.

Pension Tracking Mechanism

Q. Please can you provide some background regarding the pension tracking mechanism?

A. Yes. In HELCO's 2006 test year rate case, Docket No. 05-0315, Mr. Steven Carver's direct testimony presented the Consumer Advocate's proposed pension tracking mechanism.[1] Under the tracking mechanism proposed by the Consumer Advocate, an amount for pension costs is identified and incorporated into rates in each rate case. Once new rates are effective, and until rates are changed in a subsequent rate case, the amount of pension cost in rates is separately tracked. The mechanism proposed required that HELCO make fund contributions at the

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[1] HELCO Docket No. 05-0315 Carver Direct Testimony, CA-T-3, pages 13-49.

actuarially calculated net periodic pension cost ("NPPC") as determined under generally accepted accounting principles subject to certain exceptions.[2] (Currently SFAS No. 87, "Employers' Accounting for Pensions", is the accounting guidance that addresses the calculation of the NPPC.) At each rate case, the cumulative amount of pension cost in rates since the last rate change is compared to the cumulative amount of contributions to the pension fund. This net amount is an addition (if the cumulative fund contributions exceed the cumulative amount in rates) or deduction (if the cumulative amount in rates exceeds the cumulative fund contributions) in the calculation of rate base. The proposed pension tracking mechanism allowed HELCO to reverse the pension accumulated other comprehensive income ("AOCI") charge to equity and create a regulatory asset for financial statement purposes. The pension cost in rates is the test year NPPC plus or minus the amortization of the ending pension amount in rate base. If cumulative contributions have exceeded the cumulative pension amount in rates (an addition to rate base), the amortization would be an addition to the NPPC (i.e., future rates will be relatively higher). If the cumulative pension amount in rates have exceeded cumulative contributions (a deduction in rate base), the amortization would be a deduction from the NPPC (i.e., future rates will be relatively lower). HELCO proposed certain modifications to the tracking mechanism proposed by the Consumer Advocate to allow HELCO greater flexibility for funding more than the NPPC for certain specified reasons. In addition, HELCO proposed language to clarify how the tracking mechanism will be implemented. The Consumer Advocate and HELCO agreed to a pension

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[2] The pension funding is further restricted to the ERISA minimum and tax deductible maximum. When the NPPC is negative, there is no funding requirement.

tracking mechanism, based on the Consumer Advocate's proposal and the modifications proposed by HELCO. Pursuant to the Commission's Interim Decision and Order No. 23342 dated April 4, 2007 in HELCO's rate case, Docket No. 05-0315, the Commission approved on an interim basis, the adoption of the pension tracking mechanism (at 13), and HELCO implemented on an interim basis, the pension tracking mechanism. In the HELCO rate case, the Consumer Advocate indicated that it would propose the tracking mechanism for HELCO's affiliates. Thus, in HECO's 2007 test year rate case, Docket No. 2006-0386, HECO proposed in its update, a similar pension tracking mechanism.

In HECO's 2007 test year rate case, HECO, the Consumer Advocate and the Department of Defense (the parties in the proceeding) agreed on a pension tracking mechanism. The Commission in its Interim Decision and Order No. 23749, issued October 22, 2007, approved on an interim basis, the adoption of a pension tracking mechanism (at 18).

In this proceeding, HECO proposes to continue the pension tracking mechanism approved on an interim basis in HECO's 2007 test year rate case. The pension tracking mechanism is provided in HECO-1122.

Q. Please can you provide an overall summary of the pension tracking mechanism?

A. As discussed in HECO T-11, the pension tracking mechanism ensures that over time, the pension costs recovered through rates are based on the SFAS No. 87 net periodic pension costs ("NPPC") as reported for financial reporting purposes, and ensures that all amounts contributed to the pension trust funds (after the pension asset, which is the cumulative pension contributions in excess cumulative pension costs recognized, is reduced to zero) are in an amount equal to actual NPPC and recoverable through rates.

Q. What are the benefits of the pension tracking mechanism?

A. As discussed in direct testimony, the benefits of the pension tracking mechanism are (1) it specifies agreement on the ratemaking treatment of pension costs and pension fund contributions, thus reducing disputable items in rate cases, (2) it demonstrates rate support for the Company's pension plan and (3) it results in leveling pension costs reported on the financial statements.

Q. Please explain in general the mechanics of the pension tracking mechanism.

A. Under the pension tracking mechanism, the test year NPPC is identified and incorporated into rates in each rate case ("NPPC in rates"). Once new rates are effective and until rates are changed in a subsequent rate case, the amount of NPPC in rates and the actual NPPC is separately tracked. The difference between the NPPC in rates and the actuarially calculated NPPC for the year is charged/credited to a regulatory asset/liability. This unamortized regulatory asset/liability is included in rate base. When new rates are established in a rate case, the regulatory asset/liability is amortized over a five year period. The total test year pension cost is the test year NPPC ("NPPC in rates") plus or minus the amortization of the regulatory asset/liability. For HECO, from the start of implementation of the pension tracking mechanism until the pension asset (the cumulative pension contributions in excess of cumulative pension costs recognized) is reduced to zero, the Company would be required to fund the pension trust at the minimum required level under the law. Thereafter, the mechanism requires HECO to make fund contributions at the actuarially calculated NPPC as determined under generally accepted accounting principles, subject to certain exceptions. The pension tracking mechanism also allows HECO to reverse the pension AOCI charge to equity and create a regulatory asset for financial statement purposes. The mechanism allows the utility to recover through rates the amount of contributions to the pension trust in excess of the SFAS No. 87 NPPC that were made for specific reasons. The mechanism also addresses the situation when the SFAS No. 87 NPPC becomes negative.

Q. What is the objective of the pension tracking mechanism?

A. The objective of the pension tracking mechanism is that, over time, the Company will recover through rates SFAS No. 87 based NPPC, including the amortization of the unrecognized amounts. The pension tracking mechanism has the intended effect of balancing NPPC in rates with actual NPPC over time, but also protect ratepayers from having rates set on a level of NPPC materially higher or lower than the actual NPPC. As a result, the ratepayer remains neutral as a result of the NPPC determined for a test year. If the actual NPPC in a future year is less than what was included in rates, the difference is accumulated and returned to the ratepayer through an amortization over five years in the next rate case. If the actual NPPC in a future year is greater than what was included in rates, the difference is accumulated and an amortization over five years is included in the expenses in determining rates in the next rate case. In addition, an amount equal to the actual NPPC and recoverable through rates would be contributed to the pension trust funds (after the pension asset, which is the cumulative pension contributions in excess cumulative pension costs recognized, is reduced to zero).

Q. How is the pension tracking mechanism reflected in the test year estimates submitted under HECO's Statement of Probable Entitlement?

A. As required in the pension tracking mechanism, HECO has reflected in its Statement of Probable Entitlement results of operations, a pension expense based on the estimated SFAS No. 87 based NPPC for 2009 plus the amortization of the regulatory asset estimated as of June 30, 2009.

Q. How was the regulatory asset as of June 30, 2009 created?

A. HECO's pension tracking mechanism was approved on an interim basis in the 2007 test year rate case, in the same interim decision approving an interim rate increase. The NPPC included in determining HECO's revenue requirements in the 2007 test year rate case was $17,711,000 as reflected in Exhibit 2 page 1 of the June 2007 Update for HECO T-12 filed on June 15, 2007 in Docket No. 2006-0386. Because the actual NPPC in 2007 was the same as the test year estimate, there was no regulatory asset/liability related to the difference between the NPPC in rates and the actual NPPC as of the end of 2007. In 2008, the actual NPPC was $14,660,000 compared to the $17,711,000 included in HECO's current rates. As shown on HECO-S-1106, the difference of $3,051,000 was the regulatory liability as of the end of 2008. The estimated NPPC for 2009 is $31,489,000. Based on the assumption that interim rates would be established in July 2009, the difference between the NPPC in rates of $17,711,000 and the actual NPPC for 2009 of $31,489,000 for six months amounted to $6,889,000 ((31,489,000-17,711,000) /2). The balance as of June 30, 2009 is a regulatory asset of $3,838,000 (-3,051,000+6,889,000). The balance at June 30, 2009, amortized over five years, for the second half of 2009 amounts to $384,000. As discussed by Ms. Julie Price in HECO ST-13, the employee benefits expense includes a pension expense of $31,873,000, which reflects the estimated NPPC for 2009 as calculated by Watson Wyatt Worldwide of $31,489,000 plus the amortization (based on one fifth of the balance of the regulatory asset as of June 30, 2009) of $384,000.

Q. Has the ratepayer benefited from the pension tracking mechanism?

A. Yes. The NPPC for 2008 of $14,660,000 was less than the amount of the NPPC included in rates of $17,711,000 (amount established in the 2007 test year). Thus, for 2008, there was a difference between the NPPC included in rates and the actual NPPC of $3,051,000. Because of the tracking mechanism, the difference is reflected as part of the amortization in determining the pension expense for this test year.

Q. In the July 2, 2009 Interim Decision and Order, the Commission indicates that the pension contributions (expenses) established in this proceeding could be in effect for two years, and it could facilitate revenue collection in excess of that need to ensure the solvency of the pension funds. The commission is concerned about the over-recovery as well as the potential for actual contributions to fall below the amount recovered through rates if an economic recovery improves asset value and performances. Please comment.

A. The pension tracking mechanism addresses both of the Commission's concerns identified regarding the pension expense reflected in HECO's statement of probable entitlement. Under the pension tracking mechanism, if the NPPC in the years between rate cases are below the NPPC included in establishing rates in this proceeding, the difference will be accumulated as a regulatory liability, and the regulatory liability balance in the next rate making proceeding will be amortized over five years. If there is regulatory liability balance at the time of the next rate case, the estimated NPPC for the test year will be reduced by the amortization expense to determine the pension expense estimate for that test year. To address the concerns regarding the contributions, under the pension tracking mechanism, the Company is required to make contributions to the pension trusts based on the actual NPPC (after the pension asset is reduced to zero). Thus, over time, the

NPPC amounts that are established in rates will be contributed to the pension trust.

OPEB Tracking Mechanism

Q. Please can you provide some background regarding the OPEB tracking mechanism.

A. Yes. In HELCO's 2006 test year rate case, Docket No. 05-0315, HELCO proposed a tracking mechanism for OPEB, which mirrored the pension tracking mechanism proposed by the Consumer Advocate. Pursuant to the Commission's Interim Decision and Order No. 23342 dated April 4, 2007, in HELCO's rate case, Docket No. 05-0315, HELCO implemented on an interim basis, the OPEB tracking mechanism. The parties also agreed that a similar OPEB tracking mechanism would be proposed for HELCO's affiliates in their next rate cases.

Thus, in HECO's 2007 test year rate case, Docket No. 2006-0386, HECO proposed in its update, a similar OPEB tracking mechanism. In HECO's 2007 test year rate case, HECO, the Consumer Advocate and the Department of Defense (the parties in the proceeding) agreed on an OPEB tracking mechanism. The Commission in its Interim Decision and Order No. 23749, issued October 22, 2007, approved on an interim basis, the adoption of an OPEB tracking mechanism. The adoption of the OPEB tracking mechanism did not impact revenue requirements in the 2007 rate case proceeding. However, the OPEB tracking mechanism specifies ratemaking treatment which allows financial statement treatment of benefit costs to be smoothed based on the amount of net periodic benefit costs ("NPBC") established in this rate case and addresses potential situations in the future where contributions to OPEB trusts are not equal to the NPBC recognized. Adoption of the OPEB tracking mechanism allowed the

Company to reverse the OPEB AOCI charge to equity and create a regulatory asset for financial statement purposes.

In this proceeding, HECO proposes to continue the OPEB tracking mechanism approved on an interim basis in HECO's 2007 test year rate case. The OPEB tracking mechanism is provided in HECO-1123.

Q. Please can you provide an overall summary of the OPEB tracking mechanism?

A. As discussed in HECO T-11, the OPEB tracking mechanism ensures that over time, the OPEB costs recovered through rates are based on the SFAS No. 106 net periodic benefit ("NPBC") as reported for financial reporting purposes, and ensures that all amounts contributed to the OPEB trust funds are in an amount equal to the actual NPBC and are recoverable through rates.

Q. What are the benefits of the OPEB tracking mechanism?

A. As discussed in direct testimony, the OPEB tracking mechanism specifies the ratemaking treatment which allows financial statement treatment of benefit costs to be smoothed based on the amount of NPBC established in a rate case, and addresses potential situations in the future where contributions to OPEB trusts are not equal to the NPBC recognized.

Q. Please explain in general the mechanics of the OPEB tracking mechanism.

A. Similar to the pension tracking mechanism, an amount for OPEB costs is identified[3] and incorporated into rates in each rate case ("OPEB costs in rates"). Once new rates are effective and until rates are changed in a subsequent rate case, the amount of OPEB costs in rates is separately tracked. The difference between the OPEB costs in rates and the actuarially calculated NPBC (excluding executive

[3] OPEB costs are the test year NPBC excluding executive life costs plus SFAS No. 106 amortization.

life costs) plus the SFAS No. 106 amortization for the year is charged/credited to a regulatory asset/liability. This unamortized regulatory asset/liability is included in rate base. When new rates are established in a rate case, the regulatory asset/liability is amortized over a five year period. The total test year OPEB cost is the test year NPBC (excluding executive life costs) plus the SFAS No. 106 amortization plus or minus the amortization of the regulatory asset/liability. The mechanism requires HECO to make fund contributions at the actuarially calculated NPBC as determined under generally accepted accounting principles subject to certain exceptions. The OPEB tracking mechanism also allows HECO to reverse the OPEB AOCI charge to equity and create a regulatory asset for financial statement purposes. The mechanism allows the utility to recover through rates the amount of contributions to the OPEB trusts in excess of the SFAS No. 106 NPBC that were made for specific reasons. The mechanism also addresses the situation when the SFAS No. 106 NPBC becomes negative.

Q. What is the objective of the OPEB tracking mechanism?

A. The objective of the OPEB tracking mechanism is that, over time, the Company will recover through rates SFAS No. 106 based NPBC, including the amortization of the unrecognized amounts. The OPEB tracking mechanism has the intended effect of balancing NPBC in rates with actual NPBC over time. At the same time, the ratepayer remains neutral as a result of the NPBC determined for a test year. If the actual NPBC in a future year is less than what was included in rates, the difference is accumulated and returned to the ratepayer through an amortization over five years in the next rate case. If the actual NPBC in a future year is greater than what was included in rates, the difference is accumulated and an amortization over five years is included in the expenses in determining rates in the next rate case. In addition, an amount equal to the actual NPBC and recoverable through rates would be contributed to the OPEB trust funds.

Q. How is the OPEB tracking mechanism reflected in the test year estimates?

A. The OPEB tracking mechanism was approved on an interim basis in October 2007 in the HECO 2007 test year rate case, in the same interim decision approving an interim rate increase. The OPEB costs included in determining HECO's revenue requirements in the 2007 test year rate case was $6,350,000 as reflected on page 1 of the June 2007 Update for HECO T-12 filed on June 15, 2007 in Docket No. 2006-0386. Because the actual OPEB costs in 2007 was the same as the test year estimate, there was no regulatory asset/liability related to the difference between the OPEB costs in rates and the actual OPEB costs as of the end of 2007. In 2008, the actual OPEB costs were $5,573,000 compared to the $6,350,000 included in HECO's current rates. As shown on HECO-S-1107, the difference of $777,000 is the regulatory liability as of the end of 2008. The estimated OPEB costs for 2009 is $6,943,000. Based on the assumption that interim rates would be established in July 2009, the difference between the OPEB costs in rates of $6,350,000 and the actual OPEB costs for 2009 of $6,943,000 for six months amounted to $297,000 ((6,943,000-6,350,000)/2). The balance as of June 30, 2009, amortized over five years for the second half of 2009 amounts to $48,000. As discussed by Ms. Julie Price in HECO ST-13 and shown in HECO-S-1301, the employee benefits expense includes OPEB expense which reflects the estimated NPBC for 2009 as calculated by Watson Wyatt Worldwide of $6,941,000 less the executive life portion that has been disallowed by the Commission of $892,000, less the amortization (based on one fifth of the balance of the regulatory liability as of June 30, 2009) of $48,000, and the amortization of the SFAS No. 106 regulatory asset of $1,302,000. Ms. Price also excludes the electric discount portion of OPEB for the year in the employee benefits expense. As discussed in HECO T-11, to the extent the contributions are not currently deductible for tax purposes, negative deferred taxes are established as these contributions are temporary differences for which we are entitled to deduct for tax purposes in the future.

Q. Has the ratepayer benefited from the OPEB tracking mechanism?

A. Yes. The OPEB costs for 2008 of $5,573,000 was less than the amount of the OPEB costs in rates of $6,350,000 (amount established in the 2007 test year). Thus, for 2008, there was a difference between the OPEB costs included in rates and the actual OPEB costs of $777,000. Because of the tracking mechanism, the difference is reflected as part of the amortization in determining the OPEB expense for this test year.

Q. In the July 2, 2009 Interim Decision and Order, the Commission indicates that the OPEB contributions (expenses) established in this proceeding could be in effect for two years, and it could facilitate revenue collection in excess of that needed to ensure the solvency of the OPEB funds. The Commission is concerned about the over-recovery as well as the potential for actual contributions to fall below the amount recovered through rates if an economic recovery improves asset value and performances. Please comment.

A. The OPEB tracking mechanism addresses both of the Commission's concerns identified regarding the OPEB expense reflected in HECO's statement of probable entitlement. Under the OPEB tracking mechanism, if the actual NPBC in the years between rate cases are below the NPBC included in establishing rates in this proceeding, the difference will be accumulated as a regulatory liability, and the regulatory liability balance in the next rate making proceeding will be amortized over five years. If there is regulatory liability balance at the time of the next rate case, the estimated NPBC for the test year will be reduced by the amortization expense to determine the OPEB expense estimate for that test year. That is the situation in this ratemaking proceeding where there is a regulatory liability as June 30, 2009, and the amount is being amortized in determining the OPEB expense for this test year. To address the concerns regarding the contributions, under the OPEB tracking mechanism, the Company is required to make contributions to the OPEB trusts based on the actual NPBC. Thus, over time, the NPBC amounts that are established in rates will be contributed to the OPEB trusts.

Q. Do you have any other comments regarding the pension and OPEB tracking mechanisms?

A. Yes. The Consumer Advocate's witness, Mr. Carver, in CA-T-3, provided an analysis of including the current estimate of NPPC in the test year estimates. The Consumer Advocate's testimony notes "The bottom line is that the higher amount of NPPC included in current rates serves to reduce ratepayer exposure to a substantially higher Regulatory Asset amortization in the next rate case. Depending on the direction of the economy in the remainder of the 2009 and 2010, it is possible that the amount of NPPC in rate could be excessive and result in a negative amortization to ratepayers in the next rate case. However, even if that were to occur, ratepayer interests are protected under the pension tracking mechanism." (at 30.)

GENERAL ACCOUNTING DEPARTMENT STAFFING

Q. How many employees are in the General Accounting Department, assuming the organization prior to the March 2, 2009 reorganization?

A. There were 26 employees in the General Accounting Department in the 2007 test year interim rate case decision and 26 employees at the end of 2007. HECO added an additional Corporate Accountant in the Corporate Accounting Division in October 2008, and the there were 27 employees in the department at the end of 2008. The staffing count in the 2009 test year for the General Accounting Department is 28 employees as shown on HECO-S-1510. In HECO T-11 Rate Case Update, HECO included the addition of a new Lead Corporate Accountant in the Corporate Accounting Division of the General Accounting Department.

Q. What is the current staffing for the Corporate Accounting Division?

A. As discussed in direct testimony, HECO T-11, pages 78-80, prior to the addition of the new Corporate Accountant, there were four Corporate Accountants and one Lead Corporate Accountant. With the addition of the Corporate Accountant that was hired in October 2008, there are five Corporate Accountants and one Lead Corporate Accountant. The Corporate Accountants report to the Director of Corporate and Property Accounting, who reports to the Controller.

Q. What is the primary function of the Corporate Accounting Division?

Q. The primary function of the Corporate Accounting Division is to record and maintain the financial records of the Company, including preparing and providing internal and external financial statements and reports. Since HECO is a registrant of the Securities and Exchange Commission ("SEC") and regulated by the Public Utilities Commission of the State of Hawaii, HECO must provide a significant amount of timely and accurate monthly, quarterly and annual financial information to management, investors, regulators and the general public. Ultimately, the Corporate Accounting Division bears much of the responsibility to process and prepare the financial information in accordance with generally accepted accounting principles ("GAAP").

Q. Why was an additional corporate accountant required?

A. In this post-Enron era, the accounting pronouncements and interpretations that are being issued have increased significantly. As a result there has been an increase in the amount of analysis required to prepare the financial information in accordance with GAAP, and HECO's auditors are requiring more documentation to support the Company's analyses and conclusions.

In addition, with the release in late 2006 of the SEC's Staff Accounting Bulletin No. 108 (SAB 108) regarding quantifying and analyzing financial statement misstatements, there has been an increased emphasis in ensuring that loss contingencies, type 1 subsequent event adjustments and out-of-period adjustments, regardless of immateriality, are recorded in the proper accounting period. In the past, adjustments identified after the closing of the financial records that were considered immaterial, may have been recorded in the following month (as a subsequent month's business) rather than re-opening the Company's financial records to record the adjustment in the proper period. As a result, at the end of each quarter, there generally are multiple financial closings. To re-open, and close the Company's financial account records require a significant amount of resources. Further, as part of ensuring that all loss contingencies are liabilities and are recorded in the proper period, there has been an increased emphasis, on HECO's auditor's part, on their search for unrecorded liabilities procedures. Thus, the Company has significantly expanded its activities to ensure all costs are properly accrued. The new Corporate Accountant has allowed the work load to be spread among more people, to allow for the closing process to run smoother, and to allow for more cross-checking to increase the accuracy of our financial reporting.

Q. Why is an additional Lead Corporate Accountant required?

A. As discussed in HECO T-11 Rate Case Update, a new Lead Corporate Accountant is required to address the increase in workload as a result of the new initiatives that are being pursued in order to meet the State's clean energy policy to promote the use of renewable energy resources and/or committed to under the Hawaii Clean Energy Initiative ("HCEI") Agreement. With the HCEI Agreement, there has been and there will continue to be a number of renewable energy power purchase agreement proposals that the Company will need to evaluate. The accounting implications for each proposed power purchase agreement must be evaluated. In addition, the requirements under generally accepted accounting principles ("GAAP") will necessitate on-going continuous review and assessment of the contracts, once executed. The HCEI Agreement also contemplates additional rate cases with changes in the ratemaking model, which may require changes in accounting for certain transactions and increases the reconciliation process for the accounts impacted. In addition, the Securities and Exchange Commission ('SEC") has issued a roadmap to move U.S. Companies toward International Financial Reporting Standards ("IFRS"), which will have significant accounting and financial reporting implications for registrants of the SEC, such as HECO. The SEC's proposed roadmap for phasing in mandatory IFRS proposes filings by U.S. public companies under IFRS beginning in reporting years ending on or after December 15, 2014. Assuming IFRS will be required, HECO will need to gather information under IFRS from 2012, as three-year comparative information will be required in reporting 2014 information. In order to be in a position to gather information for 2012 transactions, HECO will need to begin reviewing all of its processes to identify accounting differences between U.S. GAAP and IFRS that impact the company. The Lead Corporate Accountant will assist in gathering information to identify the differences between US GAAP and IFRS. While the position is included as an "HCEI" position, even if none of the "HCEI" projects are pursued, HECO will continue to receive proposal for power purchase agreements which will require evaluation under EITF 01-8 and SFAS 167 (which amends FIN 46R), and the appropriate research and documentation. In addition, based on the SEC's proposed road map, it would be prudent for the Company to begin the process for converting to IFRS, such that Company would be able to comply with the SEC's requirements when they become effective.

Q. Why is it reasonable to include this position in the test year estimates?

A. In order to comply with the Interim Decision and Order, the Company removed labor costs and related benefits associated with 13 positions that were included in 2009 test year rate case, because it was identified with HCEI. This lead corporate accountant position was included in the 13 positions removed. However, as described above, this position will be doing more than work related to HCEI initiatives, and the work is not necessarily tied to the HCEI initiatives. As described, even if there were no additional HCEI initiatives, there will continue to be power purchase proposals that will require evaluations under EITF 01-8 and SFAS 167 (the amendment to FIN 46R). Further, even if the position is construed to be related to HCEI initiatives, as discussed by Mr. Alm in HECO ST-1, the position should be part of base rate activities and included in base rates. Thus, it is reasonable to include this position in the test year estimates.

Q. Has the company made efforts to fill this position?

A. Yes, this position is currently in recruitment. HECO posted the position internally and externally, and is considering a qualified candidate.

Q. How does the staffing for the General Accounting Department from the 2007 rate case interim decision compare with the 2009 test year estimate included in the settlement, assuming the March 2, 2009 reorganization was reflected in the 2007 test year interim decision?

A. In the March 2, 2009 reorganization, the Purchasing Division, which was formerly part of the Support Services Department in the Energy Delivery Process area, was transferred to the General Accounting Department. There is no change in the number of positions for the Purchasing Division as there were 15 positions in the Purchasing Division in 2007 test year interim decision, and there are 15 positions in the Purchasing Division in the 2009 test year.

MERIT SALARY ADJUSTMENT IN HECO'S JULY 8, 2009 FILING

Q. In the Interim Decision and Order ("ID&O") Section II.2.(c), the Commission required that for purposes of interim rates, for merit employees, wage levels be restricted to 2007 levels or the most recent actual labor costs filed with the Commission, taking into account the vacancy rate agreed upon by the Parties on pages 22 and 23 of the Settlement Agreement. How did the company comply with the ID&O in the July 8, 2009 filing?

A. To comply with the ID&O, in the July 8, 2009 filing, HECO made an O&M labor expense adjustment of $2,829,000, to reflect the limiting of the 2009 test year merit salary adjustment amounts at the 2007 wage levels, and an associated adjustment for payroll taxes of $203,000.

Q. How was the adjustment determined?

A. An explanation of how the adjustment was determined was provided in Exhibit 3, pages 11-13 of the July 8, 2009 filing. In addition, exhibits HECO T-11, Attachment 1 and workpapers HECO-WP-1121 through HECO-WP-1127 were provided to support the calculations. HECO also discussed the calculation with the Consumer Advocate's consultant Mr. Steven Carver on July 13, 2009.

Q. Does the Company agree that the test year estimates should reflect merit wages at the 2007 levels?

A. Ms. G. "Miki" Furuta-Okayama, in HECO-ST-15A, addresses the Company's position on merit salary increases.

ACCOUNTING FOR CAPITAL PROJECTS PLACED IN SERVICE

Q. Has the company provided its description of how it accounts for capital project costs?

A. Yes. The Company's accounting policy is provided at HECO-1118.

Q. Please describe the accounting of costs for the usual project life cycle.

A. As described in the policy, after a project is formally approved by management, a fifth segment project is activated in the MIMS (Ellipse) General Ledger and concurrently set up in the MIMS (Ellipse) project control module. Project managers then set up a project hierarchy in the MIMS (Ellipse) Project Control Module, after which all related project costs incurred are classified as construction work in progress.

During the time the project related costs are classified as CWIP, an Allowance for Funds Used During Construction ("AFUDC") is applied on the project costs. AFUDC represents the cost to finance the project during the construction period. When the facilities being constructed are declared to be used or useful, the application of AFUDC is stopped, and the project costs are closed (capitalized), i.e. transferred from CWIP to Plant in Service.

Q. What is AFUDC?

A. In simple terms, AFUDC represents the cost of investor supplied funds used by a utility to pay for capital project costs during the project's construction period. A more rigorous definition is as follows:

> "An amount recorded by a company to represent the cost of those funds used to finance Construction Work in Progress (CWIP – defined herein).
>
> These amounts:
>
> (1) are credited on the income statement during the construction period most commonly as an allowance for borrowed funds used during construction, which reduces the net interest charges, and as an allowance for (i.e., equity) funds used during construction, which adds to other income, and
>
> (2) are capitalized during the construction period along with other construction costs, to be recovered over the life of the plant through depreciation, so that the company is made whole …."[4]

Q. How is AFUDC recorded in the accounting records?

A. AFUDC is a noncash item representing the estimated composite interest costs of debt and a return on equity funds used to finance construction. AFUDC is added to the cost of a project each month in an amount equal to the AFUDC rate (percentage) times the total project cost amount included in CWIP at the beginning of the month plus 50% of the project cost incurred in the month. A contra credit is included in income.

Q. How does HECO calculate its AFUDC rate?

A. The AFUDC rate is calculated in a manner that is generally consistent with the way the Company's cost of capital is calculated in rate decisions.

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4 See 1991 Glossary of Electric Utility Terms, Edison Electric Institute, page 2.

Q. When are facilities declared to be used or useful?

A. Facilities become used when they are placed in service. Facilities become useful generally when: 1) construction is for the most part complete, 2) the facilities have been tested (if testing is possible and appropriate), and 3) the facilities are ready for use (i.e. they are able to perform their intended function, and can be energized, pending completion of related facilities, without a significant amount of additional costs incurred.)

Q. What is the interrelationship between costs being in CWIP and being transferred to plant in service?

A. Investors expect a reasonable rate of return on their funds used for the Company's capital constructions program. The return is provided through the rate of return on rate base for completed projects, and through the addition of AFUDC to the cost of projects currently being constructed.

Q. When is CT-1 expected to be declared used or useful?

A. As discussed by Mr. Robert Isler, HECO ST-17A, portions of the CIP CT-1 project have already been placed in service, and a significant portion of the CIP CT-1 project is expected to be declared used or useful at the end of July 31, 2009. The estimated amount of costs that would be transferred from CWIP to plant in service in July 2009 is $168,000,000. (Cost for the components related to the generating station, transmission line and fiber communication).

Q. What is the significance of the large amount of costs that will be transferred in July 2009 from CWIP to plant in service from an accounting and earnings stand point.

A. As discussed above, when a facility is declared used or useful, the application of AFUDC is stopped. At that point, no additional financing costs are recorded to those components of the project, and there is no contra entry to income, when costs are transferred from CWIP to plant in service. At that point, since the costs are not yet included in rate base for determining HECO's rates, the investor is not provided a return on its investment. HECO is not compensated for the carrying cost of the investment.

Q. What is the estimated amount of AFUDC for a month for CIP CT-1 based on a CWIP balance of $168 million?

A. The estimated amount of AFUDC for a month for costs in CWIP of $168 million is $1,148,000, and its earnings impact is approximately $1 million. For the components of the CIP CT-1 project that have been placed in service, and for the components that will be placed in service at the end of July 2009, until HECO is allowed to include such costs in rate base in determining HECO's rates, investors will not be able to earn a return on the cost provided for the investment in CIP CT-1. However, if the Commission provides explicit approval to continue AFUDC until the commencement of rate recovery, for those significant components that are placed in service, HECO would be allowed to accrue AFUDC to the project, and allay the impact on earnings.

Q. Does this conclude your testimony?

A. Yes, it does.

HAWAIIAN ELECTRIC COMPANY, INC.
ADMINISTRATIVE AND GENERAL EXPENSES
($ Thousands)

		(A) 2007 TY Interim (10/22/07)	(B) 2007 Actual	(C) 2008 Actual	(D) 2009 TY Settlement (5/15/09)
	ADMINISTRATIVE				
920	A&G Expense - Labor	15,810	15,767	19,331	18,558
921	A&G Expense - Non labor	12,267	13,656	16,073	15,102
922	A&G Expenses Transferred	(3,168)	(3,045)	(2,928)	(3,238)
	Total Administrative	24,909	26,378	32,476	30,422
	OUTSIDE SERVICES				
923010	Outside Services - Legal	155	46	173	131
923020	Outside Services - Other	1,165	1,350	1,492	2,535
	Total Outside Services	1,320	1,396	1,665	2,666
	INSURANCE				
924	Property Insurance	2,939	2,549	2,606	3,058
925	Injuries & Damages - Employees	6,800	7,458	6,413	7,171
	Total Insurance	9,739	10,007	9,019	10,229
	EMPLOYEE BENEFITS				
926000	Employee Pensions and Benefits	25,923	26,729	26,636	40,759
926010	Employee Benefits - Flex Credits	10,520	9,310	9,698	12,179
926020	Employee Benefits Transfer	(10,461)	(9,893)	(9,586)	(15,302)
926010	Benefits Adjustments				(819)
	Total Employee Benefits	25,982	26,146	26,748	36,817
	MISCELLANEOUS				
928	Regulatory Commission Expenses	320	512	290	440
9301	Inst. or Goodwill Advertising Expense	30	36	23	36
9302	Miscellaneous General Expenses	3,050	3,523	4,264	3,376
931	Rents Expense - A&G	2,781	3,011	2,981	3,426
932	Admin and General Maintenance	1,057	454	1,634	1,537
	Total Miscellaneous	7,238	7,536	9,192	8,815
TOTAL ADMINISTRATIVE & GENERAL EXPENSES		69,189	71,461	79,100	88,948

Totals may not add due to rounding

Notes:
(A) HECO-SWP-1102
(B) HECO-SWP-101
(C) HECO-SWP-101
(D) HECO-SWP-1101

HAWAIIAN ELECTRIC COMPANY, INC.
TEST YEAR 2009 ($1000s)

	BUDGET	BUD ADJ	NORM	DIRECT	ADJUST	UPDATE	ADJUST	SETTLE
ADMIN & GENL O & M EXPENSE								
ADMINISTRATIVE								
920 ADMIN & GENL EXP - LABR								
LABOR	19,410	7		19,417	(592)	18,825	(267)	18,558
NON-LABOR	2,988	(2,988)		0			0	0
TOTAL 920	22,398	(2,981)	0	19,417	(592)	18,825	(267)	18,558
921 ADMIN & GENL EXP - NLABR								
NON-LABOR	16,780	(1,578)		15,202	243	15,445	(343)	15,102
TOTAL 921	16,780	(1,578)	0	15,202	243	15,445	(343)	15,102
922 ADMIN EXPENSES TRANSFERRED								
NON-LABOR	(3,487)	290		(3,197)	(15)	(3,212)	(26)	(3,238)
TOTAL 922	(3,487)	290	0	(3,197)	(15)	(3,212)	(26)	(3,238)
TOTAL ADMINISTRATIVE	35,691	(4,269)	0	31,422	(364)	31,058	(636)	30,422
OUTSIDE SERVICES								
923010 OUTSIDE SERVICES - LEGAL								
NON-LABOR	131			131		131	0	131
TOTAL 923010	131	0	0	131		131	0	131
923020 OUTSIDE SERVICES - OTHER								
NON-LABOR	2,535			2,535		2,535	0	2,535
TOTAL 923020	2,535	0	0	2,535		2,535	0	2,535
923030 OUTSIDE SERVICES - ASSOC CO								
NON-LABOR	0			0			0	0
TOTAL 923030	0	0	0	0			0	0
TOTAL OS SVCS	2,666	0	0	2,666		2,666	0	2,666
TOTAL 920-923 EXPENSE	38,357	(4,269)	0	34,088	(364)	33,724	(636)	33,088

HAWAIIAN ELECTRIC COMPANY, INC.
TEST YEAR 2009 ($1000s)

	BUDGET	BUD ADJ	NORM	DIRECT	ADJUST	UPDATE	ADJUST	SETTLE
INSURANCE EXPENSE								
INSURANCE								
924 PROPERTY INSURANCE								
LABOR	216			216		216	(2)	214
NON-LABOR	2,926	(80)		2,846		2,846	(2)	2,844
TOTAL 924	3,142	(80)	0	3,062		3,062	(4)	3,058
925 INJURIES & DAMAGES								
LABOR	1,450			1,450		1,450	(13)	1,437
NON-LABOR	6,025	(283)		5,742		5,742	(8)	5,734
TOTAL 925	7,475	(283)	0	7,192		7,192	(21)	7,171
TOTAL INSURANCE	10,617	(363)	0	10,254	0	10,254	(25)	10,229

HAWAIIAN ELECTRIC COMPANY, INC.
TEST YEAR 2009 ($1000s)

	BUDGET	BUD ADJ	NORM	DIRECT	ADJUST	UPDATE	ADJUST	SETTLE
EMPLOYEE BENEFITS EXPENSE								
EMPLOYEE BENEFITS								
926000 EMPL PENSIONS AND BENEFITS								
LABOR	841			841		841	(11)	830
NON-LABOR	23,210	(2,854)		20,356	(91)	20,265	19,664	39,929
TOTAL 926000	24,051	(2,854)	0	21,197	(91)	21,106	19,653	40,759
926010 EMPL BENEFITS - FLEX CREDITS								
LABOR	211			211	(36)	175	0	175
NON-LABOR	10,999	(37)		10,962	1,044	12,006	(2)	12,004
TOTAL 926010	11,210	(37)	0	11,173	1,008	12,181	(2)	12,179
926020 EMPL BENEFITS TRANSFER								
NON-LABOR	(9,655)	692		(8,963)	(553)	(9,516)	(5,786)	(15,302)
TOTAL 926020	(9,655)	692	0	(8,963)	(553)	(9,516)	(5,786)	(15,302)
926010 EMPL BENEFITS - FLEX CREDITS								
BENEFITS ADJUSTMENTS								
NON-LABOR					(397)	(397)	(422)	(819)
TOTAL EMP BEN	25,606	(2,199)	0	23,407	(33)	23,374	13,443	36,817

HAWAIIAN ELECTRIC COMPANY, INC.
TEST YEAR 2009 ($1000s)

	BUDGET	BUD ADJ	NORM	DIRECT	ADJUST	UPDATE	ADJUST	SETTLE
OTHER ADMINISTRATIVE & GENERAL EXPENSE								
OTHER ADMIN & GENL								
928 REGULATORY COMMISSION EXPENSES								
NON-LABOR	760		(320)	440		440	0	440
TOTAL 928	760	0	(320)	440		440	0	440
9301 INSTITUTN/GOODWILL ADVERT EXP								
LABOR	14			14		14	0	14
NON-LABOR	22			22		22	0	22
TOTAL 9301	36	0	0	36		36	0	36
9302 MISCELLANEOUS GENERAL EXPENSES								
LABOR	316	(101)		215		215	(2)	213
NON-LABOR	3,888	(246)		3,642	447	4,089	(926)	3,163
TOTAL 9302	4,204	(347)	0	3,857	447	4,305	(928)	3,376
931 RENTS EXPENSE								
NON-LABOR	3,026	36		3,062	841	3,903	(477)	3,426
TOTAL 932	3,026	36	0	3,062	841	3,903	(477)	3,426
932 ADMIN AND GENL MAINTENANCE								
LABOR	195	52		247		247	(2)	245
NON-LABOR	398	1,108	(188)	1,318	120	1,438	(146)	1,292
TOTAL 932	593	1,160	(188)	1,565	120	1,685	(148)	1,537
TOTAL OTHER A&G	8,619	849	(508)	8,960	1,408	10,368	(1,553)	8,815
TOTAL A&G	83,199	(5,982)	(508)	76,708	1,011	77,719	11,229	88,948
ADMIN & GENL - TOTAL								
LABOR	22,653	(42)	0	22,611	(628)	21,983	(297)	21,686
NON-LABOR	60,546	(5,940)	(508)	54,098	1,639	55,737	11,526	67,263
TOTAL	83,199	(5,982)	(508)	76,709	1,011	77,719	11,229	88,948

HAWAIIAN ELECTRIC COMPANY, INC.
TEST YEAR 2009 ($1000s)

	SETTLE	ADJUST	RESPONSE TO ID&O
ADMIN & GENL O & M EXPENSE			
ADMINISTRATIVE			
920 ADMIN & GENL EXP - LABR			
LABOR	18,558	(1,195)	17,363
NON-LABOR			0
TOTAL 920	18,558	(1,195)	17,363
921 ADMIN & GENL EXP - NLABR			
NON-LABOR	15,102		15,102
TOTAL 921	15,102	0	15,102
922 ADMIN EXPENSES TRANSFERRED			
NON-LABOR	(3,238)		(3,238)
TOTAL 922	(3,238)	0	(3,238)
TOTAL ADMINISTRATIVE	30,422	(1,195)	29,227
OUTSIDE SERVICES			
923010 OUTSIDE SERVICES - LEGAL			
NON-LABOR	131		131
TOTAL 923010	131	0	131
923020 OUTSIDE SERVICES - OTHER			
NON-LABOR	2,535		2,535
TOTAL 923020	2,535	0	2,535
923030 OUTSIDE SERVICES - ASSOC CO			
NON-LABOR			0
TOTAL 923030		0	0
TOTAL OS SVCS	2,666	0	2,666
TOTAL 920-923 EXPENSE	33,088	(1,195)	31,893

HAWAIIAN ELECTRIC COMPANY, INC.
TEST YEAR 2009 ($1000s)

	SETTLE	ADJUST	RESPONSE TO ID&O
INSURANCE EXPENSE			
INSURANCE			
924 PROPERTY INSURANCE			
LABOR	214	(12)	202
NON-LABOR	2,844		2,844
TOTAL 924	3,058	(12)	3,046
925 INJURIES & DAMAGES			
LABOR	1,437	(70)	1,367
NON-LABOR	5,734		5,734
TOTAL 925	7,171	(70)	7,101
TOTAL INSURANCE	10,229	(82)	10,147

HAWAIIAN ELECTRIC COMPANY, INC.
TEST YEAR 2009 ($1000s)

	SETTLE	ADJUST	RESPONSE TO ID&O
EMPLOYEE BENEFITS EXPENSE			
EMPLOYEE BENEFITS			
926000 EMPL PENSIONS AND BENEFITS			
LABOR	830	(58)	772
NON-LABOR	39,929		39,929
TOTAL 926000	40,759	(58)	40,701
926010 EMPL BENEFITS - FLEX CREDITS			
LABOR	175		175
NON-LABOR	12,004		12,004
TOTAL 926010	12,179	0	12,179
926020 EMPL BENEFITS TRANSFER			
NON-LABOR	(15,302)		(15,302)
TOTAL 926020	(15,302)	0	(15,302)
926010 EMPL BENEFITS - FLEX CREDITS			
BENEFITS ADJUSTMENTS			
NON-LABOR	(819)	(441)	(1,260)
TOTAL EMP BEN	36,817	(499)	36,318

HAWAIIAN ELECTRIC COMPANY, INC.
TEST YEAR 2009 ($1000s)

	SETTLE	ADJUST	RESPONSE TO ID&O
OTHER ADMINISTRATIVE & GENERAL EXPENSE			
OTHER ADMIN & GENL			
928 REGULATORY COMMISSION EXPENSES			
NON-LABOR	440		440
TOTAL 928	440	0	440
9301 INSTITUTN/GOODWILL ADVERT EXP			
LABOR	14		14
NON-LABOR	22		22
TOTAL 9301	36	0	36
9302 MISCELLANEOUS GENERAL EXPENSES			
LABOR	213	(12)	201
NON-LABOR	3,163		3,163
TOTAL 9302	3,377	(12)	3,364
931 RENTS EXPENSE			
NON-LABOR	3,426		3,426
TOTAL 932	3,426	0	3,426
932 ADMIN AND GENL MAINTENANCE			
LABOR	245	(12)	233
NON-LABOR	1,292		1,292
TOTAL 932	1,537	(12)	1,525
TOTAL OTHER A&G	8,815	(24)	8,791
TOTAL A&G	88,948	(1,800)	87,148
ADMIN & GENL - TOTAL			
LABOR	21,686	(1,359)	20,327
NON-LABOR	67,263	(441)	66,822
TOTAL	88,948	(1,800)	87,148

INCREASES IN 2009 TEST YEAR A&G EXPENSES
FROM 2007 TEST YEAR INTERIM DECISION

The total A&G expense estimate used for the settlement agreement and statement of probable entitlement is $88,948,000. The total represents the test year estimates for Account Nos. 920 through 932. The test year 2009 amount included in the settlement and statement of probable entitlement is $19,759,000 more than the amount included in the 2007 test year interim award. The A&G expenses grouped by accounts, and the increases are shown below.

A&G Expenses	2007 TY Interim ($ Thous)	2009 TY Settlement ($ Thous)	Increase ($ Thous)
Administrative (Acct No. 920-922)	$24,909	$30,422	$ 5,513
Outside Services (Acct. No. 923010-923020)	1,320	2,666	1,346
Insurance (Acct. No. 924 and 925)	9,739	10,229	490
Employee Benefits (Acct Nos. 926000-926020)	25,982	36,817	10,835
Miscellaneous (Acct Nos. 928-932)	7,238	8,815	1,577
Total A&G Expenses	$69,189	$88,948	$19,759

Explanations for the Administrative and Outside Services categories are discussed below. The increase in the Insurance category is discussed by Mr. Russell Harris in HECO ST-12, the increase in the Employee Benefits category is discussed by Ms. Julie Price in the HECO ST-13, and the increase in the Miscellaneous category is discussed by Mr. Bruce Tamashiro in HECO ST-14.

Administrative

The Administrative group of accounts, and the associated amounts in the 2007 test year interim award, the 2009 settlement amounts and the difference are as follows:

Acct No./Description	2007 TY Interim ($ Thous)	2009 TY Settlement ($ Thous)	Increase ($ Thous)
920 - A&G Expense Labor	$15,810	$18,558	$ 2,748
921 - A&G Expense Non-labor	12,267	15,102	2,835
922 – Admin Expense Transferred	(3,168)	(3,238)	(70)
Total A&G Expense-Admin.	$24,909	$30,422	$ 5,513

The Administrative group of expenses represents the expenses incurred in connection with the general administration of the Company's operations that are not chargeable against other specific functional accounts. Administrative expenses include the labor and related non-labor costs of Company officers, as well as employees in diverse functional areas such as accounting and finance, corporate compliance, internal audit, purchasing, human resources, information services (e.g., mailing, printing, records management, and word processing), legal, government relations, regulatory affairs, environmental, information technology, safety and security, risk management, energy services, energy projects, forecasts and research, corporate communications, facilities planning, energy projects and integrated resource planning. A more detailed discussion of the types of costs included in Administrative expenses is included in HECO T-11, page 9 and HECO-1103.

Account No. 920-A&G Labor

The test year 2009 estimate used for settlement is $2,748,000 higher than the amount included in the 2007 test year interim award primarily due (1) to the general wage increases that have been granted to employees and (2) increase in positions performing administrative activities.

(1) General wage increases

General wage rates for the 2009 test year estimates used in the settlement are expected to be 7.50% (for bargaining unit employees and 7.14% (for merit employees) higher than the respective 2007 wage rates. (See attached page 7). This is revised from the estimate provided in direct testimony. In the settlement agreement, HECO agreed to reduce the merit salary increase for 2009 by 2%, to an overall merit increase of 2.5%. Ms. Furuta-Okayama in HECO ST-15A discusses the necessity for the merit salary increases and Mr. M. McInerny in HECO ST-15B discusses the bargaining unit wage increases. Note that as directed by the Commission in the interim decision and order, in HECO's revised results of operations filing on July 9, 2009, HECO made a downward adjustment to reflect merit salaries to the 2007 levels. The downward adjustment reduces the amount for Account No. 920 by approximately $996,000.

(2) Increase in positions performing administrative activities

Ms. Chiogioji in HECO ST-15 discusses the increases in the number of employees reflected in the 2007 interim decision and the 2009 test year estimates used in the settlement agreement and the statement of probable entitlement. To the extent the activities of the additional positions are administrative in nature, the labor expense for those positions would be included in Account No. 920, and contribute to the increase. HECO-1106 provides the estimated effect on Account No. 920 for additional positions included in the direct testimony of approximately $1,759,000. In HECO T-11 Rate Case Update, Attachment 3, filed on December 9, 2008, the impact to Account No. 920 for the changes in staffing identified in the Rate Case Updates amounted to a reduction of $58,000. Note that as directed by the Commission in the interim decision and order, in HECO's revised results of operations filing on July 9, 2009, HECO made a downward adjustment to remove all HCEI positions. The downward adjustment reduces the amount for Account No. 920 by approximately $199,000.

As mentioned earlier and in HECO T-11, charges to Account 920 include labor in connection with the general and administration of the Company's operations that are not chargeable against other specific functional accounts. The labor expenses for time spent on specific projects that are administrative in nature are included in Account 920. To the extent that there are more administrative type projects in 2009, such as the Ellipse 6 upgrade, and to the extent departments that normally do not charge their time to Account No. 920 are involved in the project, labor charges to Account No. 920 would be higher in 2009 test year estimates.

<u>Account No. 921-A&G Non-Labor</u>
The test year 2009 estimate for Account No. 921 used for the settlement agreement is $2,835,000 higher than the amount included in the 2007 test year rate case interim award. In HECO T-11, pages 19-26, HECO describes the primary reasons for the increases in the test year estimates from actual 2007 expenses, and those reasons are generally the reasons for the increase from the 2007 test year rate case interim award. Specifically, the increase is primarily due to:

1) Consultant fees for internal audits
2) Information Technology and Services ("ITS") charges
3) Ellipse 6 software
4) eMESA software
5) Amortization of HR suite
6) Treasury Management System upgrade
7) Higher HEI charges to HECO

1) <u>Consulting fees for Internal Audit</u>. As stated in HECO T-11, pages 19-21, Internal Audit consultant fees are to co-source conducting independent analyses and review of risk management practices, review of corporate governance process of HECO and its subsidiaries, reviewing organizational activities and processes and providing recommendations for improving existing business practices, and performing special studies and examinations requested by management. Prior to 2004, HECO's internal audit staff conducted the activities described above. Since that time, the Internal Audit staff has been spending a significant amount of its resources on evaluating the design and testing the operating effectiveness of the Company's internal controls over financial reporting in order to comply with the requirements of SOX. In addition, there have been more information technology systems, applications and devices installed or are being installed that require Internal Audit's resources to ensure accuracy of data outputs and security and protection of equipment and information. As a result of dedicating Internal Audit resources to the SOX and information technology efforts, minimal amount of resources have been spent conducting independent analyses, risk reviews, and monitoring and testing operational, financial and compliance risk of the Company. The consultant services fees for co-sourcing will provide the resources required for the Internal Audit area to conduct independent analyses, review organizational activities and processes, provide recommendations for improving existing business practices and evaluate the risk management process of the Company. Standard and Poor's has announced that it will begin Enterprise Risk Management reviews in its ratings of non-financial companies starting in 2009, and it is important that HECO enhance its process to manage enterprise

risk.

In response to CA-IR-237, HECO described how the $750,000 estimate was determined. The estimate was based on the risk assessment and audit plan for the periods May 2008 through April 2009 (year 1) and May 2009 through April 2010 (Year 2) as prepared the Corporate Audit and Compliance Department ("CACD") and presented to HECO's Audit Committee in May 2008. From the two year audit plan, the $750,000 forecast represents the approximate cost of completing the proposed audit projects scheduled to occur between January and December 2009. In response to CA-IR-238, HECO provided information supporting the need for co-sourced services from KMH LLP.

2)ITS charges. As discussed in HECO T-11, page 21, the ITS department operates and maintains the information technology ("IT") systems used at HECO. ITS costs are generally charged to the ITS Clearing Account and allocated or "costed" to the various capital, O&M and clearing accounts through the ITS costing process. In HECO T-11, pages 47-54 discusses the ITS costs (costs charged to the ITS Clearing Account) for the test year and the allocation or "costing" process. The amounts for ITS included in Account 921, represent the ITS costs related to the administrative function. In 2009, the ITS charges "costed" to Account No. 921 are higher than in 2007 because the ITS costs are estimated to be higher as explained in HECO T-11, pages 50-54. HECO also provide its ITS costing model in response to CA-IR-235.

3) Ellipse 6 software. As discussed in HECO T-11 pages 21-22 and reiterated here, the Company's core business system, Ellipse (formerly referred to as Mincom Information Management System, or MIMS, which was purchased from Mincom, Inc., an Australian based company) was implemented effective January 1, 1999. HECO is required to implement periodic software upgrades based on the vendor software life cycle. The last MIMS upgrade HECO implemented was in 2002-2003, with a go-live in October 2003. The latest support schedule for the version of Ellipse currently being run by HECO (Ellipse 5.2.3.8) is for full standard support through the first quarter of 2010, optional extended support thorough the first quarter of 2012 and time and materials support thereafter. The costs included in Account No. 921 relate to the software for the upgrade.

4) eMESA software. As discussed in HECO T-11, page 22, the eMESA software is a 3rd party web based application developed by Dimension Technology Solutions ("DTS"), an authorized Mincom partner, that extends certain Ellipse functions on to a user friendly web interface. This includes the maintenance work scheduling function, the document management function, equipment register search function and requisition creation/approval functions. This software will allow our operating area to better schedule and maintain data related to overhauls, and work management.

5) Amortization of HR Suite. As discussed in HeCO T-11, page 22, the HR suite software project was the subject of Docket No. 2006-0003, and the Commission approved in

Decision and Order No. 23413 issued May 3, 2007, HECO, HELCO and MECO's request to defer certain software costs development costs for the HR Suite project, accumulate AFUDC on the deferred cots during the deferral period, amortize the deferred costs over a twelve year period, and include the unamortized costs in rate base. The HR Suite project is expected to be completed in 2009, and amortization would begin in the month following when the software is ready for use.

6) Treasury Management System upgrade. As discussed in HECO T-11, pages 22-23, HECO has been using its current treasury management system, ICMS, for nearly 20 years. The system has been in service since 1989 and is reaching its limitations. A newer system would provide more efficient data management, better controls and the ability to interface with various financial institutions' web applications. Such enhancements will allow HECO to mechanize fund transfers and recording of these transactions in the general ledger. Also, the ICMS vendor may discontinue future software support of the older version HECO is using as they dedicate resources to newer versions of their software. HECO is in the process of implementing the system.

7) HEI Charges to HECO. A description of HEI charges to HECO is provided in HECO T-11, pages 23-26. HEI charges to HECO included in Account No. 921 for 2009 is $2,156,000 compared to $1,635,000 in the 2007 test year. HECO T-11, pages 25-26, discusses the increased in charges from the actual charges for 2007. Below is a discussion of the increase in the charges from the amount included in the 2007 test year interim decision, which is generally the same as discussion in HECO T-11..
First, HEI charges to HECO in 2009 reflect the charges for the HEI Internal Auditor, who started in July 2007, and was not included in the estimates used for the 2007 interim. In 2009, the HEI Internal Auditor anticipates spending approximately 50% of his time on HECO matters. Second, an HEI Vice President – General Counsel, Chief Administrative Officer was hired in August 2007, and was not included in the estimates used for the 2007 rate case interim. The HEI Vice President – General Counsel, Chief Administrative Officer is responsible for HEI's continuous compliance with all laws, regulations and administrative orders. He is responsible for working closely with HECO's general counsel to coordinate legal work across HECO and the other HEI subsidiaries. HEI's charges to HECO are expected to be higher as the HEI VP General Counsel estimates spending 25% of his time working on the HECO matters related to 1) corporate governance issues, 2) Securities and Exchange Commission work as it relates to HECO, 3) assisting HECO's legal department and 4) administering the hotline for whistleblower complaints for the Company. Third, HEI charges to HECO for 2009 also reflect a 2.5% adjustment for estimated cost increases. Fourth, HECO's test year estimate is based on the HEI allocation factors for 2008, which are based on recorded 2007 information. HECO's equity percentage as a percentage of total subsidiary equity was higher at the end of December 2007 compared to the end of December 2005 (which was used to determine the HEI allocation factors for the 2007 estimate.)

Account No. 922 – A&G Expense Transferred

The estimated amount transferred represents the portion of the total costs charged to Account Nos. 920 –A&G Expense-labor and 921-A&G Expense-non-labor that relate to plant construction or services provided by HECO to affiliated companies and outside third parties. The increase reflects the higher cost charged to Account No. 921- A&G expenses.

Outside Services

The Outside Services group of accounts, and the associated amounts in the 2007 test year interim award, the 2009 settlement amounts and the difference are as follows:

Acct No./Description	2007 TY Interim ($ Thous)	2009 TY Settlement ($ Thous)	Increase (Decrease) ($ Thous)
923010- Outside Services-legal	$ 155	$ 131	($ 24)
923020 – Outside Services-Other	1,165	2,535	1,370
Total Outside Services	$ 1,320	$ 2,666	$ 1,346

Account No. 9230020-Outside Services-Other

The test year 2009 estimate used for settlement is $1,370,000 higher than the amount included in the 2007 test year interim decision. As discussed in HECO T-11, pages 34-37, the increase in costs from 2007 is primarily due to consultant fees related to Ellipse Upgrade implementation and consultant fees related to the eMESA software implementation. The benefits of installing the software are included in the discussion regarding increased costs in Account No. 921. In HECO T-11, pages 34-37, HECO provides a description of the consultant costs for software implementation.

HAWAIIAN ELECTRIC COMPANY, INC.
EFFECT OF GENERAL PAY INCREASE

RELATIVE WAGE RATES

	2007		2008		2009	
	BU	Merit	BU	Merit	BU	Merit
JAN	1.0000	1.0000	1.0350	1.0401	1.0750	1.0816
FEB	1.0000	1.0000	1.0350	1.0401	1.0750	1.0816
MAR	1.0000	1.0000	1.1050	1.0401	1.0750	1.0816
APR	1.0000	1.0000	1.0350	1.0401	1.0750	1.0816
MAY	1.0000	1.0350	1.0350	1.0764	1.0750	1.1032
JUN	1.0000	1.0350	1.0350	1.0764	1.0750	1.1032
JUL	1.0000	1.0350	1.0350	1.0764	1.0750	1.1032
AUG	1.0000	1.0350	1.0350	1.0764	1.0750	1.1032
SEP	1.0000	1.0375	1.0350	1.0795	1.0750	1.1065
OCT	1.0000	1.0375	1.0350	1.0795	1.0750	1.1065
NOV	1.0000	1.0375	1.0350	1.0795	1.0750	1.1065
DEC	1.0000	1.0375	1.0350	1.0816	1.0750	1.1086
TOTAL	12.000	12.290	12.490	12.786	12.900	13.167
	(A)	(B)	(C)	(D)	(E)	(F)

					BU	Merit
Percentage increase 2009 over 2007 (G)	BU	(E-A)/A	Merit	(F-B)/B	7.50%	7.14%

Assumptions:

BU Increases	11/1/2007	3.5% of 10/31/07 rates retroactive payment in 3/08
	1/1/2009	4.0% of 10/31/07 rates
Merit Increases	5/1/2007	3.5% of 4/30/2007 rates
	9/1/2007	0.25% of 4/30/2007 rates
	11/1/2007	0.25% of 4/30/2007 rates retroactive payment in 1/08
	5/1/2008	3.5% of 4/30/08 rates
	9/1/2008	0.30% of 4/30/2008 rates
	12/1/2008	0.20 % of 4/30/08 rates
	5/1/2009	2.0% of 4/30/09 rates
	9/1/2009	0.30% of 4/30/2009 rates
	12/1/2009	0.20% of 4/30/09 rates

HAWAIIAN ELECTRIC COMPANY, INC.
TEST YEAR 2009 ($1000s)

	2007 INT	2007 ACT	2008 ACT
ADMIN & GENL O & M EXPENSE			
ADMINISTRATIVE			
920 ADMIN & GENL EXP - LABR			
LABOR	15,810	13,835	17,319
NON-LABOR	0	1,932	2,012
TOTAL 920	15,810	15,767	19,331
921 ADMIN & GENL EXP - NLABR			
NON-LABOR	12,267	13,655	16,073
TOTAL 921	12,267	13,655	16,073
922 ADMIN EXPENSES TRANSFERRED			
NON-LABOR	(3,168)	(3,045)	(2,928)
TOTAL 922	(3,168)	(3,045)	(2,928)
TOTAL ADMINISTRATIVE	24,909	26,377	32,476
OUTSIDE SERVICES			
923010 OUTSIDE SERVICES - LEGAL			
NON-LABOR	155	46	173
TOTAL 923020	155	46	173
923020 OUTSIDE SERVICES - OTHER			
NON-LABOR	1,165	1,350	1,492
TOTAL 923020	1,165	1,350	1,492
923030 OUTSIDE SERVICES - ASSOC CO			
NON-LABOR	0	0	0
TOTAL 923030	0	0	0
TOTAL OS SVCS	1,320	1,396	1,665
TOTAL 920-923 EXPENSE	26,229	27,773	34,141

HAWAIIAN ELECTRIC COMPANY, INC.
TEST YEAR 2009 ($1000s)

	2007 INT	2007 ACT	2008 ACT
INSURANCE EXPENSE			
INSURANCE			
924 PROPERTY INSURANCE			
LABOR	199	164	191
NON-LABOR	2,740	2,385	2,414
TOTAL 924	2,939	2,549	2,605
925 INJURIES & DAMAGES			
LABOR	1,375	1,572	1,511
NON-LABOR	5,425	5,886	4,902
TOTAL 925	6,800	7,458	6,413
TOTAL INSURANCE	9,739	10,007	9,018

HAWAIIAN ELECTRIC COMPANY, INC.
TEST YEAR 2009 ($1000s)

	2007 INT	2007 ACT	2008 ACT
EMPLOYEE BENEFITS EXPENSE			
EMPLOYEE BENEFITS			
926000 EMPL PENSIONS AND BENEFITS			
LABOR	580	621	636
NON-LABOR	25,343	26,108	26,000
TOTAL 926000	25,923	26,729	26,636
926010 EMPL BENEFITS - FLEX CREDITS			
LABOR	174	90	110
NON-LABOR	10,346	9,220	9,588
TOTAL 926010	10,520	9,310	9,698
926020 EMPL BENEFITS TRANSFER			
NON-LABOR	(10,461)	(9,893)	(9,586)
TOTAL 926020	(10,461)	(9,893)	(9,586)
TOTAL EMP BEN	25,982	26,146	26,748

HAWAIIAN ELECTRIC COMPANY, INC.
TEST YEAR 2009 ($1000s)

	2007 INT	2007 ACT	2008 ACT
OTHER ADMINISTRATIVE & GENERAL EXPENSE			
OTHER ADMIN & GENL			
928 REGULATORY COMMISSION EXPENSES			
NON-LABOR	320	512	290
TOTAL 928	320	512	290
9301 INSTITUTN/GOODWILL ADVERT EXP			
LABOR	11	4	10
NON-LABOR	19	32	13
TOTAL 9301	30	36	23
9302 MISCELLANEOUS GENERAL EXPENSES			
LABOR	347	296	307
NON-LABOR	2,703	3,227	3,958
TOTAL 9302	3,050	3,523	4,265
931 RENTS EXPENSE			
NON-LABOR	2,781	3,010	2,981
TOTAL 932	2,781	3,010	2,981
932 ADMIN AND GENL MAINTENANCE			
LABOR	149	77	117
NON-LABOR	908	377	1,517
TOTAL 932	1,057	454	1,634
TOTAL OTHER A&G	7,238	7,535	9,193
TOTAL A&G	69,189	71,461	79,100
ADMIN & GENL - TOTAL			
LABOR	18,645	16,659	20,201
NON-LABOR	50,543	54,802	58,899
TOTAL	69,189	71,461	79,100

HAWAIIAN ELECTRIC COMPANY, INC.
ADMINISTRATIVE AND GENERAL EXPENSES
($ Thousands)

A	B	C	D	E	F	G
			ID&O ADJUSTMENTS			
		Settlement	HCEI Positions	Emp. Ben rel. to CT-1	2007 Salary Levels	Resp. to ID&O
	ADMINISTRATIVE					
920	A&G Expense - Labor	**18,558**	(199) L	0	(996) L	**17,363**
921	A&G Expense - Non labor	**15,102**	0	0	0	**15,102**
922	A&G Expenses Transferred	**(3,238)**	0	0	0	**(3,238)**
	Total Administrative	**30,422**	(199) L	0	(996) L	**29,227**
	OUTSIDE SERVICES					
923010	Outside Services - Legal	**131**	0	0	0	**131**
923020	Outside Services - Other	**2,535**	0	0	0	**2,535**
	Total Outside Services	**2,666**	0	0	0	**2,666**
	INSURANCE					
924	Property Insurance	**3,058**	0	0	(12) L	**3,046**
925	Injuries & Damages - Employees	**7,171**	0	0	(70) L	**7,101**
	Total Insurance	**10,229**	0	0	(82) L	**10,147**
	EMPLOYEE BENEFITS					
926000	Employee Pensions and Benefits	**40,759**	0	0	(58) L	**40,701**
926010	Employee Benefits - Flex Credits	**12,179**	0	0	0	**12,179**
926020	Employee Benefits Transfer	**(15,302)**	0	0	0	**(15,302)**
926010	Benefits Adjustments	**(819)**	(303) NL	(138) NL		**(1,260)**
	Total Employee Benefits	**36,817**	(303)	(138)	(58) L	**36,318**
	MISCELLANEOUS					
928	Regulatory Commission Expenses	**440**	0	0	0	**440**
9301	Inst. or Goodwill Advertising Expense	**36**	0	0	0	**36**
9302	Miscellaneous General Expenses	**3,376**	0	0	(12) L	**3,364**
931	Rents Expense - A&G	**3,426**	0	0	0	**3,426**
932	Admin and General Maintenance	**1,537**	0	0	(12) L	**1,525**
	Total Miscellaneous	**8,815**	0	0	(24) L	**8,791**
TOTAL A&G EXPENSES		88,948	(502)	(138)	(1,160)	87,148

Totals may not add due to rounding

Account 920	(199)
Benefits Adjustment	(303)
Revised Schedules Resulting from Interim D&O, HECO T-11, Att. 2, p. 1	(502)
Revised Schedules Resulting from Interim D&O , Att. A, p. 1	(138)
Revised Schedules Resutling from Interim D&O, HECO T-11, Att. 1, p. 1	(1,160)

Notes:

L Labor

NL Non-Labor

Hawaiian Electric Company, Inc.
Regulatory Asset - NPPC vs NPPC in Rates
($ Thousands)

Balance, 12/31/07		$ -	[A]
2008			
NPPC in rates ($17,711) vs. NPPC for 2008 ($14,660)		$ (3,051)	[B]
Balance, 12/31/08 (Regulatory Liability)		(3,051)	[C] = [A] + [B]
2009 test year			
NPPC in rates ($17,711) vs NPPC for 2009 ($31,489) (6 months)		6,889	[D]
Balance as of June 30, 2009	3,838		[E]=[C]+[D]
Amortization (1/5 of 6/30/09 balance) for 1/2 year		(384)	[F]= [E]/5 * 0.5
Balance, 12/31/09 estimate (Regulatory Asset)		$ 3,454	[G]=[C]+[E]+[F]
Average		202	[H] = ([C]+[G]/2

Sources:
[B] NPPC in rates per Docket No. 2006-0386; NPPC estimates per Watson Wyatt
[D] NPPC estimate per Watson Wyatt

[A] Tracking mechanism implemented in Oct. 2007 with interim D&O in Docket No. 2006-0386.
NPPC in rates equaled SFAS 87 NPPC.
[E] Amortization

Hawaiian Electric Company, Inc.
Pension Asset
1987-2009
($ Thousands)

	Year	Contributions to Trust	NPPC Accrual	Ending Pension Asset Balance
		A	B	C= Prior C+A-B
	1986			$ 480
	1987	$ 8,736	$ 9,216	-
	1988	8,308	8,308	-
Ba	1989	9,007	9,007	-
	1990	9,740	9,740	-
	1991	10,618	10,618	-
	1992	11,382	11,382	-
NI	1993	10,940	10,940	-
	1994	10,925	10,925	-
	1995	9,058	6,408	2,650
	1996	6,972	8,381	1,241
	1997	5,876	7,117	-
	1998	2,206	1,871	335
	1999	0	(1,074)	1,409
	2000	0	(19,322)	20,731
	2001	0	(20,465)	41,196
	2002	0	(15,656)	56,852
	2003	13,394	5,894	64,352
	2004	15,186	(1,547)	81,085
	2005	6,000	4,588	82,497
	2006	0	14,237	68,260
	2007	0	17,711	50,549
	2008	0	14,660	35,889
	2009 *	2,739	31,489	7,139
	Total	$ 141,087	$ 134,428	

Recorded balances for 1987-2005.

* NPPC accrual amounts for 2009 is an estimate.

Hawaiian Electric Company, Inc.
OPEB
Regulatory Liability - NPBC vs NPBC in rates
($ Thousands)

Balance, 12/31/07		$ -	[A]
2008			
NPBC in rates ($6,350) vs NPBC for 2008 ($5,573)		(777)	[B]
Balance, 12/31/08 estimate		(777)	[C] = [A] + [B]
2009 test year			
NPBC in rates ($6,350) vs NPBC for 2008 ($6,943) (6 months)		297	[D]
Balance as of June 30, 2009	(480)		[E]=[C]+[D]
Amortization (1/5 of 6/30/09 balance) for 1/2 year		48	[F]=[E]/5 * 0.5
Balance, 12/31/09 estimate		(432)	
Average		(605)	

OPEB in rates:		
NPBC (2007)	6,291	
Amortization of 106 Regulatory Asset	1,302	
Electric Discount	(408)	
Executive Life	(835)	
OPEB in rates	6,350	Per Docket No. 2006-0386
2008 OPEB		
NPBC	5,549	Per Watson Wyatt
Amortization of 106 Regulatory Asset	1,302	Per page 2
Electric Discount	(408)	same as OPEB in rates
Executive Life	(870)	Per Watson Wyatt
2008 OPEB	5,573	
2009 OPEB		
NPBC	6,941	Per Watson Wyatt
Amortization of 106 Regulatory Asset	1,302	per page 2
Electric Discount	(408)	same as OPEB in rates
Executive Life	(892)	per Watson Wyatt
2009 OPEB for comparison	6,943	

Notes:
[A] Tracking mechanism implemented in October 2007 with interim D&O in Docket No. 2006-0386.
[A] & [B] Estimates per Watson Wyatt

Hawaiian Electric Company, Inc.
SFAS 106 OPEB Regulatory Asset
1994-2009
($ Thousands)

Year	Amortization & Adjustment	Ending FAS 106 Reg Asset Balance
	A	B Prior Year B - A
1994		$ 24,882
1995	$ 2,751	22,131
1996	1,302	20,829
1997	1,302	19,528
1998	1,302	18,226
1999	1,302	16,924
2000	1,302	15,622
2001	1,302	14,320
2002	1,302	13,018
2003	1,302	11,717
2004	1,302	10,415
2005	1,302	9,113
2006	1,302	7,811
2007	1,302	6,509
2008	1,302	5,207
2009	1,302	3,905
Total	$ 20,977	

Source: Recorded balances for 1994-2008.

Hawaiian Electric Company, Inc.

1994-2009
($ Thousands)

Year	NPBC Actuarial Accrual*	less: Payments & Electric Discount to Retirees[2]	less: Contributions to Trusts	add: Trust Reimbursement[2]	less: Executive Life Adj	Timing & Reconciling Differences	Ending OPEB Liability Balance	
	A	B	C	D	E	F	G=Prior G+ A-B-C+D-E+F	
1994							$ 21,286	
1995	$ 15,725	$ 3,227	$ 14,270	$ -	$ 609		18,904	
1996	14,936	3,858	15,580	7,059	657	26	20,829	
1997	14,393	3,257	15,024	3,009	671	248	19,528	
1998	9,285	3,280	10,046	2,995	540	284	18,226	
1999	3,574	3,398	4,357	3,936	519	(538)	16,924	
2000	1,761	4,106	2,605	4,103	458	3	15,622	
2001	2,107	1,633	2,857	1,635	551	(2)	14,320	
2002	4,263	3	4,927		637	3	13,018	
2003	6,906	1	7,364		844	1	11,717	
2004	6,233	4	6,680		855	4	10,415	
2005	7,034		7,435		900	0	9,113	
2006	6,620		7,060		862	0	7,811	1
2007	6,291		6,758		835	0	6,509	1
2008	5,549		5,981		870	0	5,207	1
2009	6,941		7,351		892	0	3,905	1

* Amount is actuarial NPBC accrual amount. NPBC in rates is provided on page 1 of 3.

Recorded balances for 1994-2005.

1 2006 through 2009 "OPEB liability balances" are for illustrative purposes.

2 From 1995-2001, HECO made payments to retirees and was reimbursed by the trust. Beginning in 2002, trust reimbursements for electric discount to retirees are shown net in col. C.

SUPPLEMENTAL TESTIMONY OF
RUSSELL R. HARRIS

DIRECTOR
RISK MANAGEMENT
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Insurance as included in Administrative and General Expenses

INTRODUCTION

Q. Please state your name and business address.

A. My name is Russell R. Harris, and my business address is 220 South King Street, Honolulu, Hawaii 96840.

Q. By whom are you employed and in what capacity?

A. I am the Director of Risk Management for Hawaiian Electric Company, Inc. ("HECO" or the "Company"). My educational background and experience are shown in HECO-1200. I have previously submitted written direct testimony in this case as HECO T-12.

Q. What is the reason for your supplemental testimony?

A. My supplemental testimony is submitted in response to item (v) in Section III. (j) of the Interim Decision and Order issued on July 2, 2009 in this docket, concerning increases in administrative and general ("A&G") expenses, insofar as those expenses relate to the insurance group of accounts in A&G expenses.

Q. What are the accounts and test year 2009 amounts for the insurance group of accounts?

A. As shown in HECO-1201, page 1, the insurance group of A&G accounts and the associated test year 2009 amounts, totaling $10,254,000, are as follows:

Acct. No.	Description	Test Year 2009 Estimate
924	Property Insurance	$ 3,062,000
925	Injuries and Damages	7,192,000
	Total (Net of budget and G/L code adjustments)	$10,254,000

Q. Were the test year 2009 amounts for the insurance group of accounts reduced as a result of the settlement agreement?

A. Yes. As a result of the settlement agreement, the test year 2009 amounts for the insurance group of accounts were reduced by a total of $25,000, as shown in HECO-S-1201, page 1. Expenses were reduced by $10,000 ($2,000 reduction for NARUC 924 and $8,000 for 925) as a result of the reversal of the O&M expenses associated with the Customer Information System ("CIS") and by $15,000 ($2,000 for NARUC 924 and $13,000 for 925) for the merit salary reduction. The explanations for these reductions were provided in the Stipulated Settlement Letter, pages 24-27. With these adjustments, the updated amounts for settlement are:

Acct. No.	Description	2009 Stipulated Settlement
924	Property Insurance	$ 3,058,000
925	Injuries and Damages	7,170,000
	Total (Net of budget, settlement and G/L code adjustments)	$10,228,000

Q. Why are accounts 924, 925.01 and 925.02 grouped together in your testimony, and what are the differences among these accounts?

A. These accounts are grouped together because they represent expenses incurred in order to prevent or control the financial impact of accidental losses on the Company. Account 924, "property insurance," includes the cost of insurance for utility property owned by the Company and claims payments or reserves for damage to this property not covered by insurance.

Account 925, "injuries & damages," has two components:

1) Employees (account 925.01) includes the cost of insurance to protect the Company against injuries to employees as well as claims payments or reserves for costs not covered by insurance. This component also includes the cost of safety and accident prevention.

2) Public (account 925.02) includes the cost of insurance and claims payments or reserves to protect the Company against injuries to, and damage claims brought by members of the public.

Q. What are the majority of the costs in accounts 924 and 925 related to?

A. The majority of costs are related to insurance premiums and absorbed losses. HECO-S-1201 reflects these costs. Of the $10,228,000 for 2009, premiums shown on HECO-S-1201, page 2 total $4,142,000 or 40.5% and losses shown on page 3 total $3,319,000 or 32.5% for a combined total of approximately 73%. Labor costs on page 5 of $1,650,000 comprise 16.1%. Approximately two thirds of the labor is related to workers compensation and the safety program ($1,060,000 or 64.2%).

Q. How do the 2009 test year stipulated settlement amounts compare with the Company's 2007 test year interim award?

A. As reflected in HECO-S-1201, page 1, the $10,228,000 stipulated settlement has increased from the 2007 test year interim award of $9,740,000. This $488,000 increase is 5.0% higher than the 2007 test year interim award. 30.0% or $146,000 of the higher amount of $488,000 reflected in these accounts is actually not additional, but transferred from another department, as further discussed below.

Q. What are the major components of NARUC accounts 924 and 925 and how do each compare with their respective portions of 2009 stipulated settlement amounts versus the Company's 2007 test year interim award?

A. There are five cost groups which make up these accounts: (1) insurance premiums, (2) absorbed loss costs, (3) other non-labor, (4) labor and (5) safety program non-labor. As shown in HECO-S-1201, pages 2 through 6, all groups compare very closely, with the exception of absorbed losses costs (which are higher than the 2007 costs) and the safety program (which is projected to be lower). The group components compare as follows:

Component	2007 Interim	2009 Stip Stlmt	% Diff	$ Diff
Premiums	$4,127,000	$4,142,000	0.4%	$15,000
Absorbed Losses	$2,882,000	$3,319,000	15.1%	$437,000
Other Non-Lbr	$541,000	$577,000	6.7%	$36,000
Labor	$1,574,000	$1,650,000	4.8%	$76,000
Safety Non-Lbr	$1,509,000	$1,338,000	(11.3%)	($171,000)
Less G/L Code	($893.000)	($797,000)	(10.8%)	$96,000
Total	$9,740,000	$10,228,000	5.0%	$488,000

Q. Why are the absorbed losses projected to be 15.1% higher in test year 2009 compared to the interim settlement 2007 losses?

A. The actual increase in the Company cost for absorbed losses is 10.1% or $291,000, of which 5.1% or $146,000 was transferred from another department's responsibility, as discussed in HECO T-12, page 34, lines 9-19. The 10.1% increase is primarily based on trending historical recorded costs. Losses projected in the stipulated 2009 settlement are based on trending of historical recorded losses in the three major areas of (1) property/boiler and machinery, (2) workers compensation, and (3) liability as shown in HECO-1202, 1203 and 1204 respectively. HECO-1202, page 1 uses 98 months of recorded losses to trend to the property/boiler & machinery projection of $269,000 for test year 2009. 98 months are deemed to be sufficient to smooth the volatility of these losses between years. HECO-1203 utilizes the historical cash flow requirements for all open workers compensation claims, regardless of the year of occurrence, to project the test year 2009 estimate of $1,459,000. This method has been utilized in several past rate cases as discussed in HECO T-12, page 23, line 19 through page 25, line 10. Liability losses are projected in HECO-1204 using 98 months of historical recorded loss expenses to project the 2009 test year amount of $1,410,000 which was increased by $181,000 to $1,591,000 including $146,000 previously projected in another department's budget, as discussed in HECO T-12, page 34, lines 9-19.

Q. Why are the safety program non-labor costs projected to be significantly lower in test year 2009 compared to the interim settlement 2007 losses?

A. As shown in HECO-1201, page 6, the original 2009 budget was adjusted downward to remove a portion of projected costs related to safety incentives. If this $163,000 amount had not been removed, the total for 2009 would have been $1,501,000, or a reduction of only $8,000 from the $1,509,000 safety non-labor cost shown in HECO-S-1201, page 6.

Q. Which area of the costs for absorbed losses is causing the large increase between 2009 test year estimates and the 2007 test year interim award.

A. As shown in HECO-S-1201, page 3, property losses are actually less in the 2009 estimate. The workers compensation losses are showing an increase of $127,000 and the liability losses are projected to be $336,000 higher. As noted above, historical recorded losses are utilized to provide reasonable estimates of future costs with the exception of the additional costs for liability losses.

Company Policy with Respect to Insurance Coverage

Q. What is the Company's policy with respect to purchasing insurance coverage?

A. The Company's policy is to minimize the combined cost of insurance and absorbed losses. Please refer to HECO T-12, page 7, lines 1-9 for details.

Q. How does the Company determine insurance requirements for a given category of insurance?

A. Please refer to HECO T-12, page 7, line 22 through page 8, line 20 for details on identifying risks of loss, determining severity and probability of losses that may occur, and conducting a competitive bidding process through our insurance broker for applicable insurance that is determined to be the Company's prudent risk financing tool.

Q. Does HECO take steps to control the costs in NARUC accounts 924 and 925?

A. Yes. For example, although premiums are heavily influenced by market conditions, they are also influenced by HECO's loss history which compares premiums paid to insurers versus losses paid by the insurers. HECO practices a number of loss control methods to prevent losses or minimize the impact of losses that do occur. The in-house safety program provides extensive loss control for workers compensation, fire protection and public liability exposures. Outside loss control consultants are contracted for surveying the property/boiler and machinery risk exposures to reduce the chance of losses. In-house and outside counsel are utilized to control costs of lawsuits through effective litigation. Deductibles and retentions are maintained at significant levels to reduce the costs of premiums. The higher the deductible or retention, the less underwriters will charge for premiums, as the insured will be absorbing losses in a larger range from the first dollar. The result is that annual costs are more volatile but on average lower overall.

Q. Does this conclude your testimony?

A. Yes.

HAWAIIAN ELECTRIC COMPANY, INC.
Combined Insurance Premium, Absorbed Losses, Non Labor Expenses and Labor and Related Expenses ($000s)

Type of Expense	2007 Interim	2007 Recorded	2008 Recorded	2009 Test Yr Est	2009 Settlmt adj	2009 Settlement	2007 Interim v. 2009 Settlement *Change * Dollars	2007 Interim v. 2009 Settlement * Change * Percent
ACCOUNT 924.00, PROPERTY								
Labor	198.8	164.0	191.9	215.6	-2.0	213.6	14.8	7.5%
Non-Labor	2,855.8	2,485.2	2,526.3	2,956.2	-2.1	2,954.1	98.3	3.4%
Less: G/L Code (remove non-labor on-cost addressed by Ms. Patsy Nanbu's testimony, HECO T-11)	-115.8	-100.6	-112.6	-109.7		-109.7	6.1	-5.3%
Total Non-Labor	2,740.0	2,384.6	2,413.8	2,846.5	-2.1	2,844.4	104.4	3.8%
Combined 924	2,938.8	2,548.6	2,605.7	3,062.1	-4.1	3,058.0	119.2	4.1%
ACCOUNT 925.01, INJURIES & DAMAGES - EMPLOYEES								
Labor - Workers' Compensation	119.1	365.2	323.0	142.6		142.6	23.5	19.7%
Labor - Safety Program	898.8	837.1	830.5	930.6		930.6	31.8	3.5%
Subtotal	1,017.9	1,202.3	1,153.5	1,073.2	0.0	1,073.2	55.3	5.4%
Non-Labor - Workers' Compensation	1,666.5	1,470.4	1,310.4	1,791.0		1,791.0	124.5	7.5%
Non-Labor - Safety Program	1,508.6	1,337.5	1,389.5	1,337.6		1,337.6	-171.0	-11.3%
Subtotal	3,175.1	2,807.9	2,700.0	3,128.6	0.0	3,128.6	-46.5	-1.5%
Combined 925.01	4,193.0	4,010.2	3,853.5	4,201.8	0.0	4,201.8	8.8	0.2%
ACCOUNT 925.02, INJURIES & DAMAGES - PUBLIC								
Labor - Liability	357.6	369.8	357.4	376.3	-13.3	363.0	5.4	1.5%
Non-Labor - Liability	3,028.0	3,807.6	2,891.6	3,300.6	-8.0	3,292.6	264.6	8.7%
Combined 925.02	3,385.6	4,177.4	3,249.0	3,676.9	-21.3	3,655.6	270.0	8.0%
COMBINED ACCOUNT 925, INJURIES & DAMAGES								
Total Labor 925	1,375.5	1,572.1	1,511.0	1,449.5	-13.3	1,436.2	60.7	4.4%
Total Non-Labor 925	6,203.1	6,615.5	5,591.5	6,429.2	-8.0	6,421.2	218.1	3.5%
Less: G/L Codes	-777.0	-729.9	-689.4	-687.0	0.0	-687.0	90.0	-11.6%
Total Non-Labor 925	5,426.1	5,885.6	4,902.1	5,742.2	-8.0	5,734.2	308.1	5.7%
Combined 925	6,801.6	7,457.7	6,413.1	7,191.7	-21.3	7,170.4	368.8	5.4%
GRAND TOTAL	9,740.4	10,006.3	9,018.8	10,253.9	-25.4	10,228.5	488.1	5.0%

HAWAIIAN ELECTRIC COMPANY, INC.
Non-Labor Insurance Premiums and Related Expenses ($000's)

Type of Expense		2007 Interim	2007 Recorded	2008 Recorded	2009 Test Yr Est		2009 Settlmt adj	2009 Settlement	2007 Interim v. 2009 Settlement *Change * Dollars	2007 interim v. 2009 Settlement * Change * Percent
ACCOUNT 924.00, PROPERTY										
Property		1,649.8	1,518.4	1,541.3	1,786.7	(d)	-	1,786.7	136.9	8.3%
Boiler/Machinery		601.6	553.4	562.0	597.9	(e)	-	597.9	-3.7	-0.6%
Crime (a)		67.8	55.7	61.0	61.7		-	61.7	-6.1	-9.0%
Other (b)		2.1	4.8	-9.4	-		-	-	-2.1	-100.0%
Freight		21.9	10.1	10.7	16.8		-	16.8	-5.1	-23.3%
	Subtotal	2,343.2	2,142.4	2,165.6	2,463.1		-	2,463.1	119.9	5.1%
ACCOUNT 925.01, INJURIES & DAMAGES - EMPLOYEES										
Excess Workers' Compensation (W/C)		181.4	181.4	184.7	191.7	(f)	-	191.7	10.3	5.7%
State W/C Special Fund		55.8	17.4	59.4	14.6		-	14.6	-41.2	-73.8%
USL&H Bond		5.9	1.0	1.0	1.4		-	1.4	-4.5	-76.3%
	Subtotal	243.1	199.8	245.1	207.7		-	207.7	-35.4	-14.6%
ACCOUNT 925.02, INJURIES & DAMAGES - PUBLIC										
General Liability		1,151.5	1,082.9	1,071.1	1,121.1	(g)	-	1,121.1	-30.4	-2.6%
D&O		194.2	169.1	156.6	172.0		-	172.0	-22.2	-11.4%
Fiduciary		158.9	143.4	142.6	144.4		-	144.4	-14.5	-9.1%
Crime (c)			*55.7*	*61.0*	*61.7*			*61.7*	*61.7*	
Professional Errors & Omissions		33.2	29.2	28.4	33.6		-	33.6	0.4	1.2%
Other		3.3	2.3	0.1	-		-	-	-3.3	-100.0%
	Subtotal	1,541.1	1,426.9	1,398.7	1,471.1		0.0	1,471.1	-70.0	-4.5%
GRAND TOTAL		4,127.4	3,769.1	3,809.4	4,141.9		0.0	4,141.9	14.5	0.4%

Notes:
(a) (c) Prior to 2006, premiums for Crime were captured under Account 925.02
(b) Prior to 2007, premiums for Other were captured Under Account 925.02
(d) ($60k) reduction to property insurance premium, see HECO-1201
(e) ($20k) reduction to boiler & machinery insurance premium, see HECO-1201
(f) ($25k) reduction to excess workers compensation premium, see HECO-1201
(g) ($130k) reduction to general liability insurance premium, see HECO-1201

HAWAIIAN ELECTRIC COMPANY, INC.
Non-Labor Absorbed Losses and Expenses (000's)

Type of Expense	2007 Interim	2007 Recorded	2008 Recorded	2009 Test Yr Est		2009 Settlmt adj	2009 Settlement	2007 Interim v. 2009 Settlement *Change * Dollars	2007 Interim v. 2009 Settlement * Change * Percent
ACCOUNT 924.00, PROPERTY									
Property Losses	294.6	133.6	191.5	268.7		0.0	268.7	-25.9	-8.8%
Subtotal	294.6	133.6	191.5	268.7		0.0	268.7	-25.9	-8.8%
ACCOUNT 925.01, INJURIES & DAMAGES - EMPLOYEES									
Workers' Comp Losses	1,332.2	1,166.2	1,182.5	1,458.8		0.0	1458.8	126.6	9.5%
Subtotal	1,332.2	1,166.2	1,182.5	1,458.8		0.0	1458.8	126.6	9.5%
ACCOUNT 925.02, INJURIES & DAMAGES - PUBLIC									
Liability Losses	1,255.2	2,160.7	1,031.4	1,591.0	(a)	0.0	1591.0	335.8	26.8%
Subtotal	1,255.2	2,160.7	1,031.4	1,591.0		0.0	1591.0	335.8	26.8%
GRAND TOTAL	2,882.0	3,460.5	2,405.5	3,318.5		0.0	3,318.5	436.5	15.1%

Notes:
(a) $35k increase to liability loss projection

HAWAIIAN ELECTRIC COMPANY, INC.
Other Non-Labor Expenses (000's)

Type of Expense	2007 Interim	2007 Recorded	2008 Recorded	2009 Test Yr Est	2009 Settlmt Adj	2009 Settllmt	2007 Interim v. 2009 Settlement *Change * Dollars	2007 Interim v. 2009 Settlement * Change * Percent
ACCOUNT 924.00, PROPERTY								
Property Other Non-Labor Expenses	218.0	209.2	169.2	224.4	-2.1	222.3	4.3	2.0%
Subtotal	218.0	209.2	169.2	224.4	-2.1	222.3	4.3	2.0%
ACCOUNT 925.01, INJURIES & DAMAGES - EMPLOYEES								
Workers' Comp Other Non-Labor Expenses	91.2	104.4	-117.2	124.5	-8.0	116.5	25.3	27.8%
Subtotal	91.2	104.4	-117.2	124.5	-8.0	116.5	25.3	27.8%
ACCOUNT 925.02, INJURIES & DAMAGES - PUBLIC								
Liability Other Non-Labor Expenses	231.7	220.0	461.5	238.5	0.0	238.5	6.8	2.9%
Subtotal	231.7	220.0	461.5	238.5	0.0	238.5	6.8	2.9%
GRAND TOTAL	540.9	533.6	513.5	587.4	-10.1	577.3	36.4	6.7%

Note: "Other Non-Labor Expenses" do not include Premiums, Absorbed Losses or Safety Program related non-labor expenses.
Included are on-costs discussed in Ms. Patsy Nanbu's testimony, HECO T-11. These are adjusted by the G/L code cost reversals after all costs are combined as shown on HECO-1101, page 1.
See calculations for Other Non-Labor Expenses in HECO-WP-1203

HAWAIIAN ELECTRIC COMPANY, INC.
Labor and Related Expenses ($000's)

Type of Expense	2007 Interim	2007 Recorded	2008 Recorded	2009 Test Yr Est	2009 Settlmt Adj	2009 Settllmt	2007 Interim v. 2009 Settlement *Change * Dollars	2007 Interim v. 2009 Settlement * Change * Percent
ACCOUNT 924.00, PROPERTY								
Direct Labor	173.6	141.2	164.5	186.1	-2.0	184.1	10.5	6.1%
On-Cost	25.2	22.8	27.5	29.5		29.5	4.3	17.1%
Subtotal	198.8	164.0	191.9	215.6	-2.0	213.6	14.8	7.5%
ACCOUNT 925.01, INJURIES & DAMAGES - EMPLOYEES								
Workers' Comp Direct Labor	105.2	98.0	86.9	126.0	-13.3	112.7	7.5	7.1%
Workers' Comp Non-Prod Labor	0	252.6	223.1	0.0		0.0	-	
Workers' Comp On-Cost	13.8	14.5	13.1	16.6		16.6	2.8	20.3%
Subtotal	119.0	365.1	323.0	142.6	-13.3	129.3	10.3	8.7%
Safety Program Direct Labor	794.4	730.7	722.6	813.0		813.0	18.6	2.3%
Safety Program On-Cost	104.4	106.4	107.9	117.6		117.6	13.2	12.6%
Subtotal	898.8	837.1	830.5	930.6	0.0	930.6	31.8	3.5%
Combined Direct Labor	899.6	828.7	809.5	939.0	-13.3	925.7	26.1	2.9%
Combined Non-Prod Labor	0.0	252.6	223.1	0.0	0.0	0.0	-	
Combined On-Cost	118.2	120.9	120.9	134.1	0.0	134.1	15.9	13.5%
Total Account 925.01	1,017.8	1,202.2	1,153.5	1,073.2	-13.3	1,059.9	42.1	4.1%
ACCOUNT 925.02, INJURIES & DAMAGES - PUBLIC								
Direct Labor	315.8	321.7	309.5	328.3		328.3	12.5	4.0%
On-Cost	41.8	48.1	47.9	48.0		48.0	6.2	14.9%
Total Account 925.02	357.6	369.8	357.4	376.3	0.0	376.3	18.7	5.2%
Account 925.01 & 925.02 Direct Labor	1,215.4	1,150.4	1,119.0	1,267.4		1267.4	52.0	4.3%
Account 925.01 & 925.02 Non-Prod Labor	0.0	252.6	223.1	0.0		0.0	-	
Account 925.01 & 925.02 On-Cost	160	169	169	182		182.2	22.2	13.8%
Total 925.01 & 925.02	1,375.4	1,572.0	1,511.0	1,449.5	0.0	1,449.5	74.1	5.4%
GRAND TOTAL	1,574.2	1,736.0	1,702.9	1,665.1	-15.3	1,649.8	75.6	4.8%

HAWAIIAN ELECTRIC COMPANY, INC.
Safety Program Expenses ($000's)
Included in Account 925.01

Description of Safety Program Expenses	2007 Interim	2007 Recorded	2008 Recorded	2009 Test Yr Est		2009 Settlmt Adj	2009 Settllmt	2007 Interim v. 2009 Settlement *Change * Dollars	2007 Interim v. 2009 Settlement * Change * Percent
Labor (asbestos work, accident investigation, training)	898.8	837.1	830.5	930.6		0.0	930.6	31.8	3.5%
Non-Labor:									
Safety Materials Purchased by Safety Division (SS) (equipment, promotional, educational)	189.0	244.8	176.0	111.8		0.0	111.8	-77.2	-40.8%
Safety Materials Purchased Outside Safety Division	163.8	149.5	199.2	102.9		0.0	102.9	-60.9	-37.2%
Information Services	90.3	100.7	109.3	118.2		0.0	118.2	27.9	31.0%
Transportation/Travel	184.7	182.6	183.2	124.2		0.0	124.2	-60.5	-32.7%
Outside Services (a)	282.6	214.4	308.8	449.2	(c)	0.0	449.2	166.6	58.9%
Other Costs (b)	598.2	445.5	413.1	431.3		0.0	431.3	-166.9	-27.9%
Subtotal Non-Labor	1,508.6	1,337.5	1,389.5	1,337.6		0.0	1,337.6	-171.0	-11.3%
GRAND TOTAL SAFETY PROGRAM	2,407.4	2,174.6	2,220.0	2,268.2		0.0	2,268.2	-139.2	-5.8%

(a) "Outside Services" includes fire protection system, outside laboratory analysis, physical (motor vehicles), membership dues, communications, staff training, heavy truck licensure, and records/reports.

(b) "Other Costs" include primarily on-costs which will be reduced by G/L Code reversals after all NARUC 925 components are combined (see HECO-1101, page 1). For Test Year 2009, these costs total $425.7 of $439.7 shown above for Safety. G/L Code Adjustments are addressed by Ms. Patsy Nanbu in HECO T-11.

(c) $163.2k reduction to normalize the safety banquet and awards at 40% of projected cost based on historical frequency (2 out of 5 years)

($thousands)	2009 Bud	Normalization	Adjustment
Safety Celebration (See HECO-WP-1202, page 124)	162.0	-60%	(97.2)
Process Area Team Safety Awards (See HECO-WP-1202, pages 126-127)	96.0	-60%	(57.6)
Merit Supervisor Safety Awards (See HECO WP-1202, page 128)	14.0	-60%	(8.4)
Total	272.0		(163.2)